

# Consideration of Comments

## Project 2007-12 Frequency Response

The Frequency Response Drafting Team thanks all commenters who submitted comments on the first formal posting for Project 2007-12 Frequency Response. ~~These~~This standards ~~were~~was posted for a 45-day public comment period from October 25, 2011 through December 9, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 43 sets of comments, including comments from approximately 133 different people from approximately 86 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

Based on the comments received and the drafting team's discussion of those comments, the drafting team made the following changes to the proposed Standard, definitions, and associated documents:

There should be a brief explanation for "why" the SDT made these changes. . . .

- Modified the definition for Frequency Response Measure (FRM)
- Modified the definition of Frequency Bias Setting
- ~~Removed the references~~ to Reserve Sharing Groups (RSGs) and replaced ~~it~~them with Frequency Response Sharing Group
- Created a definition for Frequency Response Sharing Group (FRSG)
- Modified Requirement R2 to provide clarity and incorporate Requirement R5
- Created a new Requirement R3 for entities using variable Frequency Bias
- Removed the requirement for operating in Tie Line Bias mode as duplicative of other requirements in other standards
- Removed Requirement R5 and combined it into revised Requirement R2 and new Requirement R3
- ~~Modifying~~Modified Attachment A to provide additional clarity
- ~~Modifying~~Modified Attachment B to provide additional clarity
- Made conforming changes to Measures, Evidence Retention, and VSLs to align with language in the revised requirements
- Re-wrote the Background Document to incorporate additional language for justification of requirements and provide additional clarity

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

- A few stakeholders questioned a Requirement for the BA to provide Frequency Response when they typically do not own generation. The SDT explained that the NERC Functional Model and FERC cited the BA as the responsible party for providing Frequency Response and that this was outside the scope of the industry approved SAR. The SDT also stated that there were several different methods available to the BA to provide Frequency Response and that the SDT had included these in the Background Document. The SDT further stated that any entity could

submit a SAR addressing this issue to the SC for consideration and that the SDT supported this option.

- A couple of the commenters felt that the median was not the proper method to use for the calculation of the FRM and that the RSG was not fully explained. The SDT stated that the ~~Statisticians~~ statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA's Frequency Response. The SDT also noted that while the median was not perfect, the median approaches a BA's typical performance after 15-20 observations and that more observations give a higher confidence in the estimate of the BA's performance.
- Some commenters disagreed with the VSLs developed for R1, stating that the VSLs were tied to Interconnection performance as well as the BA's performance.
- Some commenters disagreed with proceeding through development of the standard before the proposed measures have been thoroughly field tested.
- Some commenters disagreed with the mixing of mandatory compliance elements and guidance elements in Attachment A and asked to have all the mandatory elements moved into the body of the standard.

These were all significant issues and should be identified here, along with the SDTs' reason for not making a change as requested.

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

[http://www.nerc.com/filez/standards/Frequency\\_Response.html](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 of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at [herb.schrayshuen@nerc.net](mailto:herb.schrayshuen@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

<sup>1</sup> The appeals process is in the Reliability Standards Development Procedures: <http://www.nerc.com/standards/newstandardsprocess.html>.

DRAFT

*Index to Questions, Comments, and Responses*

1. The SDT has made minor modifications to the proposed definitions to provide additional clarity. Do you agree that these modifications provide sufficient clarity? If not, please explain in the comment area ..... X
2. The SDT has made minor modifications to the Requirements R1 through R4 to provide additional clarity. Do you agree that these modifications provide sufficient clarity to comply with the standard? If not, please explain in the comment area. .... X
3. The SDT has developed VRFs for the proposed Requirements within this standard. Do you agree that these VRFs are appropriately set? If not, please explain in the comment area. .... X
4. The SDT has developed Measures for the proposed Requirements within this standard. Do you agree with the proposed Measures in this standard? If not, please explain in the comment area ..... X
5. The SDT has developed VSLs for the proposed Requirements within this standard. Do you agree with these VSLs? If not, please explain in the comment area..... X
6. The SDT divided the previously posted “Attachment A – Background Document” into two documents to provide additional clarity. The first document “Attachment A- Supporting Document” which details the methods used to develop the events to be analyzed, the FRO, FRM and Frequency Bias Setting. Do you agree that the revised Attachment A – Supporting Document provides sufficient clarity on the methodologies to be used? If not, please explain in the comment area. .... X
7. The second document “BAL-003-1 Background Document” provides information behind the development of the standard. Do you agree that this new document provides sufficient clarity as to the development of the standard? If not, please explain in the comment area. .... X
8. The SDT has developed a new document titled Attachment B – Process for Adjusting Bias Setting Floor. This document is intended to provide the methodology the ERO will use to reduce the minimum Frequency Bias Setting to become closer to natural Frequency Response. Do you agree that this document provides clear and concise instructions for the ERO to follow? If not, please explain in the comment area. .... X
9. The SDT has provided an additional spreadsheet, FRS Form 2, to assist the Balancing Authority in providing the data needed to comply with the proposed standard. Do you agree that this spreadsheet is useful and the instructions are meaningful? If not, please explain in the comment area. .... X
10. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard BAL-003-1. .... X

**The Industry Segments are:**

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	James Murphey	BPA	WECC	1									
2.	Bart McManus	BPA	WECC	1									
3.	David Kirsch	BPA	WECC	1									
2.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District	X		X	X	X	X				
<b>Additional Member Additional Organization Region Segment Selection</b>													
1.	Tino Zaragoza	IID	WECC	1									
2.	Jesus Sammy Alcaraz	IID	WECC	3									
3.	Diana Torres	IID	WECC	4									
4.	Marcela Caballero	IID	WECC	5									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5. Cathy Bretz		IID	WECC 6										
3.	Group	Guy Zito	Northeast Power Coordinating Council										X
Additional Member		Additional Organization	Region	Segment Selection									
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10									
2.	Greg Campoli	New York Independent System Operator	NPCC	2									
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1									
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1									
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10									
6.	Brian Evans-Mongeon	Utility Services	NPCC	8									
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5									
8.	Kathleen Goodman	ISO - New England	NPCC	2									
9.	Chantel Haswell	FPL Group, Inc.	NPCC	5									
10.	David Kiguel	Nydro One Networks Inc.	NPCC	1									
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1									
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9									
13.	Bruce Metruck	New York Power Authority	NPCC	6									
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10									
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1									
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1									
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5									
18.	Saurabh Saksena	National Grid	NPCC	1									
19.	Michael Schiavone	National Grid	NPCC	1									
20.	Wayne Sipperly	New York Power Authority	NPCC	5									
21.	Tina Teng	Independent Electricity System Operator	NPCC	2									
22.	Donald Weaver	Neqw Brunswick System Operator	NPCC	2									
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1									
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3									
4.	Group	Will Smith	MRO NSRF										X
Additional Member		Additional Organization	Region	Segment Selection									
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6									
2.	CHUCK LAWRENCE	ATC	MRO	1									

Group/Individual	Commenter	Organization	Registered Ballot Body Segment												
			1	2	3	4	5	6	7	8	9	10			
3. TOM WEBB	WPS	MRO	3, 4, 5, 6												
4. JODI JENSON	WAPA	MRO	6												
5. KEN GOLDSMITH	ALTW	MRO	4												
6. ALICE IRELAND	NSP (XCEL)	MRO	1, 3, 5, 6												
7. DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6												
8. ERIC RUSKAMP	LES	MRO	1, 3, 5, 6												
9. JOE DEPOORTER	MGE	MRO	3, 4, 5, 6												
10. SCOTT NICKELS	RPU	MRO	4												
11. TERRY HARBOUR	MEC	MRO	1, 3, 5, 6												
12. MARIE KNOX	MISO	MRO	2												
13. LEE KITTELSON	OTP	MRO	1, 3, 4, 5												
14. SCOTT BOS	MPW	MRO	1, 3, 5, 6												
15. TONY EDDLEMAN	NPPD	MRO	1, 3, 5												
16. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6												
17. RICHARD BURT	MPC	MRO	1, 3, 5, 6												
5.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X									
<b>Additional Member Additional Organization Region Segment Selection</b>															
1.	Andy Burch	EEL	SERC	5											
2.	Bob Dalrymple	TVA	SERC	1, 3, 5, 6											
3.	Brad Gordon	PJM	SERC	2											
4.	Vicky Budreau	SCPSA	SERC	1, 3, 5, 6											
5.	Sam Holeman	Duke	SERC	6, 1, 3, 5											
6.	Cindy Martin	Southern Co	SERC	1, 5											
7.	Scott Brame	NCEMC	SERC	1, 3, 4, 5											
8.	Wayne Van Liere	LGE-KU	SERC	3											
9.	Larry Akens	TVA	SERC	1, 3, 5, 6											
10.	John Troha	SERC Reliability Corp.	SERC	10											
6.	Group	Robert Rhodes	SPP Standards Review Group		X										
<b>Additional Member Additional Organization Region Segment Selection</b>															
1.	John Allen	City Utilities of Springfield	SPP	1, 3, 5											
2.	David Dockery	Associated Electric Cooperative	SERC	1, 3, 5											

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
3.	Lisa Duffey	Cleco Power	SPP	1, 3, 5										
4.	Jonathan Hayes	SPP	SPP	2										
5.	Steve Haun	Lincoln Electric System	MRO	1, 3, 5										
6.	Tony McMurtry	Lafayette Utilities System	SPP	NA										
7.	Dave Milliam	Kansas City Power & Light	SPP	1, 3, 5, 6										
8.	Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5										
9.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6										
7.	Group	Steve Rueckert	Western Electricity Coordinating Council											X
No additional members listed.														
8.	Group	Frank Gaffney	Florida Municipal Power Agency		X		X	X	X	X	X			
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4										
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3										
3.	Jim Howard	Lakeland Electric	FRCC	3										
4.	Lynne Mila	City of Clewiston	FRCC	3										
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1										
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4										
7.	Randy Hahn	Ocala Utility Services	FRCC	3										
9.	Group	Thomas McElhinney	JEA Electric Compliance		X		X		X					
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	John Babik	JEA Electric Compliance	FRCC	5										
2.	Ted Hobson	JEA Electric Compliance	FRCC	1										
3.	Garry Baker	JEA System Operations	FRCC	3										
10.	Group	Al DiCaprio	ISO/RTO Council Standards Review Committee			X								
<b>Additional Member Additional Organization Region Segment Selection</b>														
1.	Charles Yeung	SPP	SPP	2										
2.	Kathleen Goodman	ISO-NE	NPCC	2										
3.	Gary DeShazo	CAISO	WECC	2										
4.	Greg Campoli	NYISO	NPCC	2										
5.	Steve Myers	ERCOT	ERCOT	2										



Group/Individual		Commenter	Organization	Registered Ballot Body Segment																
				1	2	3	4	5	6	7	8	9	10							
6.	Don Weaver	NBSO	NPCC 2																	
7.	Mark Thompson	AESO	WECC 2																	
8.	Ben Li	IESO	NPCC 2																	
11.	Group	Jason L. Marshall	ACES Power Marketing Standards Collaborators							X										
<b>Additional Member</b>		<b>Additional Organization</b>		<b>Region</b>	<b>Segment Selection</b>															
1.	Mark Ringhausen	Old Dominion Electric Cooperative		RFC	3, 5, 6															
2.	James Jones	Arizona Electric Power Cooperative/Southwest Transmission Cooperative		WECC	1, 5, 6															
3.	Erin Woods	East Kentucky Power Cooperative		SERC	1, 3, 5, 6															
12.	Group	Joe Tarantino	Sacramento Municipal Utility District (SMUD)	X		X	X	X	X											
<b>Additional Member</b>		<b>Additional Organization</b>		<b>Region</b>	<b>Segment Selection</b>															
1.	Kevin Smith	Balancing Authority of Northern California (BANC)		WECC	1															
13.	Individual	Emily Pannel	Southwest Power Pool Regional Entity																	X
14.	Individual	Cindy Oder	Salt River Project	X		X		X	X											
15.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X											
16.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X											
17.	Individual	Antonio Grayson	Southern Company	X		X		X	X											
18.	Individual	Howard F. Illian	Energy Mark, Inc.														X			
19.	Individual	Don McInnis	Florida Power & Light Company	X		X		X												
20.	Individual	Carlos J. Macias	FPL	X		X		X	X											
21.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X											
22.	Individual	Thomas Washburn	FMPP							X										
23.	Individual	Alice Ireland	Xcel Energy	X		X		X	X											
24.	Individual	Kathleen Goodman	ISO New England Inc		X															
25.	Individual	John Tolo	Tucson Electric Power	X																

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Dennis Sismaet	Seattle City Light	X		X	X	X	X				
27.	Individual	Michael Falvo	Independent Electricity System Operator		X								
28.	Individual	John Bussman	Associated Electric Cooperative Inc	X		X		X	X				
29.	Individual	Rich Salgo	NV Energy	X		X		X					
30.	Individual	Thad Ness	American Electric Power	X		X		X	X				
31.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
32.	Individual	Louis C. Guidry	Cleco Corporation	X		X		X	X				
33.	Individual	H. Steven Myers	ERCOT		X								
34.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
35.	Individual	Curtis Crews	Texas Reliability Entity										X
36.	Individual	Mark B Thompson	Alberta Electric System Operator		X								
37.	Individual	Anthony Jablonski	ReliabilityFirst										X
38.	Individual	Brenda Powell	Constellation Energy Commodities Group						X				
39.	Individual	Kirit Shah	Ameren	X		X		X	X				
40.	Individual	Michael Brytowski	Great River Energy	X		X		X	X				
41.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
42.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
43.	Individual	Robert Blohm	Keen Resources Asia Ltd.								X		

1. **The SDT has made minor modifications to the proposed definitions to provide additional clarity. Do you agree that these modifications provide sufficient clarity? If not, please explain in the comment area.**

**Summary Consideration:** The majority of the commenters felt that the SDT should use the term “prevent” instead of “discourage” in the definition of FRM. The SDT explained that it did not want to use the word “prevent” since the SDT believes that the word would imply that you could stop withdrawal. The SDT does not believe that you can totally stop the withdrawal but you can discourage it.

Many of the commenters did not agree with requiring the BA to provide Frequency Response. The NERC Functional Model and FERC cite the BA as the responsible party for providing Frequency Response. There are several different methods available to the BA to provide Frequency Response and these are included in the Background Document.

A couple of the commenters felt that the median was not the proper method to use for the calculation of the FRM and that the RSG was not fully explained. Statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA’s Frequency Response. While the median is not perfect, the median approaches a BA’s typical performance after 15-20 observations and more observations give a higher confidence in the estimate of the BA’s performance.

Some commenters had concerns about the use of the RSG as a means to provide Frequency Response, and in response the SDT modified the Background Document to further explain how an RSG (now FRSG) could be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”

Organization	Yes or No	Question 1 Comment
Seattle City Light	Negative	<p>Answer: No. Comments: LADWP and SCL recommend the following change to the definition of Frequency Bias Setting. LADWP believes that this change increases the clarity of the definition:</p> <p>Original A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to account for the Balancing Authority’s Frequency Response contribution to the</p>

Organization	Yes or No	Question 1 Comment
		<p>Interconnection, and discourage response withdrawal through secondary control systems.</p> <p>Proposed Change A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's Frequency Response contribution to the Interconnection, and prevent response withdrawal through secondary control systems</p>
<p><b>Response: The SDT disagrees with your definition. The SDT considered using the term "prevent" but decided to use the term "discourage" instead. The SDT believes that the word "prevent" would imply that you could stop withdrawal. The SDT does not believe that you can totally stop the withdrawal but you can discourage withdrawal.</b></p>		
Alliant Energy Corp. Services, Inc.	Negative	<p>The definition of Frequency Bias Setting should focus on what it is. balancing Authorities do not supply energy. suggest revising it to "A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to approximate the expected natural response provided by the assets within the respective Balancing Authority's area."</p>
<p><b>Response: The SDT agrees that the Balancing Authority does not directly supply energy. However, the NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</b></p> <p><b>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR<sub>[MEL1]</sub>.</b></p> <p><b>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not</b></p>		

Organization	Yes or No	Question 1 Comment
<p>outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>The SDT also believes that the definition you have suggested is basically saying the same thing as the definition the SDT has chosen to use.</p>		
Potomac Electric Power Co.	Negative	The proposed new Definitions do not stand alone and are also linked to Attachments.
<p><b>Response: The SDT has modified the definitions to no longer reference any other documents.</b></p>		
ISO/RTO Council Standards Review Committee	No	<p>(1) In our previous comments, we suggested to drop the definitions for the terms FRM and FRO in favor of providing the needed wording in the standard itself to take care of the specific details. The SDT did not adopt our suggestion with the reason that these definitions will be used by other standards in the future. That’s fair enough. However, the FRM definition: “The median of all the Frequency Response observations reported annually on FRS Form 1” is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an Attachment to a standard. In the current NERC Glossary of Terms, there is no such precedence that a definition must rely on the requirements or details in a standard for completeness. Also, it is very cumbersome that when changes are made to FRS Form 1, the definition must be posted for industry comment and balloting, and vice versa. When other standards begin using the term, there will be cross references between standards. This further complicates the update/approval process without any appreciable value. Once again, we strongly urge the SDT to consider dropping these definitions, and have the details fully specified in the standard body itself. This will eliminate that cross reference issue. After all, the definition for FRM is a simple</p>

Organization	Yes or No	Question 1 Comment
		<p>sentence and does not provide any clarity or specific details that cannot be presented by using appropriate wording in a requirement.</p> <p>(2) The definition of Frequency Bias Setting, if retained, should focus on what it is. Balancing Authorities do not supply energy. We suggest to revise it to: Frequency Bias Setting A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's (BA's) Area Control Error (ACE) equation to approximate the expected natural response provided by the assets within the respective Balancing Authority's area.</p>
<p><b>Response:</b> The SDT believes that these terms will be used in later version of the BAL Standards. The term FRO is presently being used in the development of a new standard (BAL-012-1 Planning Reserves). The SDT has modified the definitions to no longer reference any other documents.</p> <p>The SDT agrees that the Balancing Authority does not directly supply energy. However, the NERC <u>Functional Model Technical Document</u> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>The SDT also believes that the definition you have suggested is basically saying the same thing as the definition the SDT has</p>		

Organization	Yes or No	Question 1 Comment
<b>chosen to use.</b>		
Duke Energy	No	<p>Duke Energy would suggest removing “usually” from the Frequency Bias Setting definition, as the value in the ACE equation must be in terms of MW/0.1Hz in order for ACE to be correctly calculated. We apologize for missing this point in the last round of comments. Though some would argue that the last phrase of the definition is more of an explanation of a function rather than a definition, we support keeping the phrase inserted, as it should be recognized that the intent is to account for the frequency response contribution AND keep the FBS slightly larger (in magnitude) than the average estimated response, to better discourage withdrawal, which was also recognized by Nathan Cohn.</p> <p>Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?</p>
<p><b>Response: It is the understanding of the SDT that EMS systems could use different methods implementing the ACE calculation. The SDT therefore believes that the term “usually” is more appropriate.</b></p> <p><b>The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.”</b></p>		
Independent Electricity System Operator	No	<p>In our previous comments, we suggested to drop the definitions for the terms FRM and FRO in favor of providing the needed wording in the standard itself to take care of the specific details. The SDT did not adopt our suggestion with the reason that these definitions will be used by other standards in the future. That’s fair enough. However, the FRM definition: “The median of all the Frequency Response observations reported annually on FRS Form 1” is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an attachment to a standard. In the current NERC Glossary of Terms, there is no such precedence that a</p>

Organization	Yes or No	Question 1 Comment
		<p>definition must rely on the requirements or details in a standard for completeness. Also, it is very cumbersome that when changes are made to FRS Form 1, the definition must be posted for industry comment and balloting, and vice versa. When other standards begin using the term, there will be cross references between standards. This further complicates the update/maintenance problem without any appreciable value.</p> <p>Once again, we strongly urge the SDT to consider dropping these definitions, and have the details fully specified in the standard body. This will eliminate the cross reference issues. After all, the definition for FRM is a simple sentence and does not provide any clarity or specific details that cannot be addressed by providing the appropriate wording in a requirement.</p> <p>With this cross-reference issue, combined with the issues associated with Attachments A and B (see our comments under Q6, below), we are unable to support this standard at this time.</p>
<p><b>Response: The SDT believes that these terms will be used in later version of the BAL Standards. The term FRO is presently being used in the development of a new standard (BAL-012-1 Planning Reserves). The SDT has modified the definitions to no longer reference any other documents.</b></p>		
Keen Resources Asia Ltd.	No	<p>In the Standard, the definition of Frequency Response Measure (FRM) is statistically wrong. The median is an improper statistical measure of Frequency Response because--it truncates large excursions which are the specific subject of Frequency Response control, not normal operating frequency errors which are self-correcting and are the subject of CPM control;--it is non-linear; and therefore--it is non-summable over the interconnection; in other words, the individual BA medians don't add up to the interconnection median, in complete incompatibility with CPM control which requires summability of BA performances into the interconnection's</p>



Organization	Yes or No	Question 1 Comment
		<p>performance. Moreover, it is mathematically impossible to sum the medians of the BAs in a Reserve Sharing Group (RSG) into the RSG's median: in other words, the RSG's median cannot represent the sum of the medians of its members. The last paragraph on page 5 of the Background Document is patently wrong, invented, and supported in no probability &amp; statistics literature whatsoever. As a practicing statistician, I hereby give testimony to the utter falsehood of the statement that "In general, statisticians use the median as the best measure of central tendency when a population has outliers." (See <a href="http://www.robertblohm.com/BestStatistic.doc">http://www.robertblohm.com/BestStatistic.doc</a> for an explanation of "best statistic" which is a highly technical and central topic in modern probability theory and statistics.) Also, "outliers" are falsely and rhetorically claimed to be "noise" when in fact they are the "events" that are the specific subject of Frequency Response. It is well known that they do not "fit" a normal distribution. They are distinct from the normal operating errors that are the subject of CPM control. The paragraph does correctly conclude that the linear regression more accurately incorporates outliers than the median does, although the paragraph uses rhetoric by calling this improvement "skew" as if it is distortionary when, in fact, the median distorts the reality.</p>
<p><b>Response: The word "average" is a generic term to represent central tendency. The term is often used <u>synonymously</u> with the arithmetic "mean".</b></p> <p><b>The issue with measuring frequency response is that a BA's calculated performance (as opposed to actual performance) is highly variable event to event. This is particularly true for a single BA in a multi-BA Interconnection.</b></p> <p><b>Calculated Frequency Response has a very large noise to signal ratio. A 5,000 MW BA in the East typically is only called to contribute about 10-15 MW for the loss of a large unit. Its minute to minute load changes can easily wash this contribution out. An arithmetic mean or regression analysis will be influenced by noise-induced outliers.</b></p> <p><b>Statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA's Frequency Response.</b></p>		

Organization	Yes or No	Question 1 Comment
<p>A regression would be appropriate if you were trying to forecast “calculated” frequency response for a BA in a multi-BA interconnection.</p> <p>While not perfect, the median approaches a BA’s typical performance after 15-20 observations. More observations give a higher confidence in the estimate of the BA’s performance.</p>		
Manitoba Hydro	No	It is not clear why the term “Single Event Frequency Response Data (SEFRD)” has been removed from the standard but is still used and defined in the Background Document and Attachment A.
<p>Response: The SDT removed the term because it was not being used within the standard itself. It was only being used in the calculation of the FRM. There is no need to create a NERC Glossary defined term if it is not being used in the standard.</p>		
Seattle City Light	No	LADWP and SCL recommend the following change (in red) to the definition of Frequency Bias Setting. LADWP believes that this change increases the clarity of the definition:OriginalA number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to account for the Balancing Authority’s Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.Proposed ChangeA number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to account for the Balancing Authority’s Frequency Response contribution to the Interconnection, and discourage prevent response withdrawal through secondary control systems
<p>Response: The SDT disagrees with your definition The SDT considered using the term “prevent” but decided to use the term “discourage” instead. The SDT believes that the word “prevent” would imply that you could stop withdrawal. The SDT does not believe that you can totally stop the withdrawal but you can discourage withdrawal.</p>		
Los Angeles Department of Water	No	LADWP recommends the following change to the definition of Frequency Bias Setting (replace the word "discourage" with the word "prevent").

Organization	Yes or No	Question 1 Comment
and Power		<p>LADWP believes that this change increases the clarity of the definition:OriginalA number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to account for the Balancing Authority’s Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.Proposed ChangeA number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to account for the Balancing Authority’s Frequency Response contribution to the Interconnection, and prevent response withdrawal through secondary control systems</p>
<p><b>Response: The SDT disagrees with your definition. The SDT considered using the term “prevent” but decided to use the term “discourage” instead. The SDT believes that the word “prevent” would imply that you could stop withdrawal. The SDT does not believe that you can totally stop the withdrawal but you can discourage withdrawal.</b></p>		
Progress Energy	No	<p>PGN supports the collective comments of SERC members.We feel that the last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. While the SERC OC Standards Review Group understands the statement, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word “Interconnection”.</p> <p>Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?</p>
<p><b>Response: The SDT thanks you for your suggestion but feels that the statement referenced provides further clarity and has decided to <u>not further modify the definition based on your comments</u> <del>leave the definition as presently stated</del> [MEL2].</b></p> <p><b>The SDT has modified the definition for FRM to state that it is the responsibility of the BA. The definition now read “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.”</b></p>		

Organization	Yes or No	Question 1 Comment
ERCOT	No	<p>RE: Frequency Response Obligation (FRO) definition: ERCOT suggests changing “Balancing Authority’s” to “Balancing Authority Area’s” as follows: The Balancing Authority Area’s share of the required Frequency Response needed for the reliable operation of an Interconnection.</p> <p>A BA that does not own generation resources cannot provide Frequency Response, it can only schedule and dispatch available resources capable of such; . The BA should be responsible for taking action to schedule resources that are capable of frequency response, and monitoring to assure frequency response performance. The GOP (possibly the LSE when demand side performance is involved) must be accountable for performing. However, there is nothing in this requirement to encourage the owner of a resource who chooses not to provide frequency response to come to the table. There is nothing in this standard that uniformly requires all frequency response providers to perform. This is likely to be detrimental to the performance of a BAA and unfairly sanctions those willing to perform to assure reliability while others are not required to perform.</p>
<p><b>Response: The SDT believes that the BA is the responsible entity not the BA Area.</b></p> <p><b>the NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</b></p> <p><b>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</b></p> <p><b>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not</b></p>		

Organization	Yes or No	Question 1 Comment
<p>outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p>		
Ameren	No	<p>The Frequency Response Measure (FRM) definition should include which Entity(ies) it applies to, similar to the definition of the FRO.</p>
<p>Response: The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.”</p>		
Constellation Energy Commodities Group	No	<p>The Frequency Response Obligation has two components based on Attachment 1 - an Interconnection FRO and a BA FRO. The proposed definition captures only the BA FRO.</p>
<p>Response: The definition is referencing the responsible entity, the BA. The interconnection’s FRO is only calculated as the beginning point for the determination of the BA’s FRO.</p>		
Hydro-Quebec TransEnergie	No	<p>The FRM and FRO definitions should precise that it is expressed in MW/0.1Hz.</p> <p>As for the Frequency Bias Setting definition, as written, would apply only to a multiple BA Interconnection. In a single BA Interconnection, the Frequency Bias translates the frequency error into a MW value that must be dispatched to bring back Frequency to desired value. Since Tie Lines are not controlled through AGC, there is no response withdrawal issue</p>
<p>Response: The FRM and FRO definitions have been modified to state MW/0.1Hz.</p> <p>The SDT disagrees. There can be withdrawal on any interconnection that uses a Frequency Bias estimate if that estimate is lower than Frequency Response and other factors are used to determine dispatch, i.e., future load estimate.</p>		

Organization	Yes or No	Question 1 Comment
<p>Northeast Power Coordinating Council/ISO New England Inc.</p>	<p>No</p>	<p>The FRM definition should not refer to FORM 1.</p> <p>Also, suggest the following wording for frequency bias setting: “A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to approximate the frequency response provided by the assets within the respective Balancing Authority’s area.”</p>
<p><b>Response:</b> The SDT has modified the definitions to no longer reference any other documents.</p> <p>The definition now read “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.”</p> <p>The SDT agrees that the Balancing Authority does not directly supply energy. However, the NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>The SDT also believes that the definition you have suggested is basically saying the same thing as the definition the SDT has chosen to use.</p>		

Organization	Yes or No	Question 1 Comment
MRO NSRF	No	<p>The FRM definition: “The median of all the Frequency Response observations reported annually on FRS Form 1” is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an attachment to a standard. In the current NERC Glossary of Terms, there is no such precedence that a definition must rely on the requirements or details in a standard for completeness.</p> <p>Additionally, the definition of Frequency Bias Setting should focus on what it is. Balancing Authorities do not supply energy. Suggest revising it to: Frequency Bias Setting A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to approximate the expected natural response provided by the assets within the respective Balancing Authority’s area.</p>
<p><b>Response: The SDT has modified the definitions to no longer reference any other documents.</b></p> <p>The definition now read “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.”</p> <p>The SDT agrees that the Balancing Authority does not directly supply energy. However, the NERC <u>Functional Model Technical Document</u> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p>		

Organization	Yes or No	Question 1 Comment
<p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>The SDT also believes that the definition you have suggested is basically saying the same thing as the definition the SDT has chosen to use.</p>		
Alberta Electric System Operator	No	<p>The FRO definition is specific to BAs. The Appendix 1, which is incorporated in the standard, uses this definition in relation to requirements of the Interconnection. The SDT should consider a revision of this definition that accounts for the requirements of the Interconnection versus the BA obligation to the Interconnection.</p>
<p><b>Response: The definition is referencing the responsible entity, the BA. The Interconnection’s FRO is only calculated as the beginning point for the determination of the BA’s FRO.</b></p>		
South Carolina Electric and Gas	No	<p>The last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. Therefore, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word “Interconnection”.</p> <p>Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?</p>
<p><b>Response: The SDT thanks you for your suggestion but feels that the statement referenced provides further clarity and has decided to leave the definition as presently stated.</b></p> <p>The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.”</p>		
SERC OC Standards Review Group	No	<p>We feel that the last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. While the SERC OC Standards Review Group understands the statement, we do not</p>



Organization	Yes or No	Question 1 Comment
		<p>feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word “Interconnection”. Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?</p>
<p><b>Response:</b> The SDT thanks you for your suggestion but feels that the statement referenced provides further clarity and has decided to leave the definition as presently stated.</p> <p>The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.”</p>		
Southern Company	No	<p>We suggest adding BA to the definition of Frequency Response Measure (FRM), similar to the definition for Frequency Response Obligation (FRO).</p>
<p><b>Response:</b> The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.”</p>		
Associated Electric Cooperative Inc	Yes	<p>The FRO definition incorrectly applies the historically narrow Balancing Authority scope of responsibility, while the FRM definition does not address applicability at all. But the BAL-003-1 Standard itself identifies RSGs (where applicable) and BAs as the Responsible Entities within scope of this standard. For consistency, AECE recommends using “Responsible Entities (e.g. Reserve Sharing Groups - where applicable, and Balancing Authorities)” in both the FRO and FRM definitions. Rationale: This change should help future-proof the definition, should more specific “frequency response” or “spinning reserve” sharing groups later surface within our industry.</p> <p>AECE agrees with the Frequency Bias Setting definition’s inclusion of a bit more functionality than typical. We however recommend replacing “to account for the Balancing Authority’s Frequency Response contribution to</p>

Organization	Yes or No	Question 1 Comment
		<p>the Interconnection, and discourage response withdrawal through secondary control systems”, with “to support their Frequency Response contribution to the Interconnection”. Rationale: Readability, and clarity on the “discouraging withdrawal...” phrase, which should reside in the Background document.</p>
<p><b>Response:</b> The SDT believes that using the term “Responsible Entities” would cause confusion since different standards could define a Responsible Entity differently. However, the SDT has defined a new term “Frequency Response Sharing Group” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members<sup>[MEL3]</sup>.”</p> <p><b>The SDT thanks you for your suggestion for the definition of Frequency Bias Setting but feels that the statement referenced provides further clarity and has decided to leave the definition as presently stated.</b></p>		
SCE&G	Affirmative	<p>The last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. Therefore, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word “Interconnection”.</p> <p>Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?</p> <ul style="list-style-type: none"> <li>o The utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as “Frequency Response Sharing</li> </ul>
<p><b>Response:</b> <b>The SDT thanks you for your suggestion for the definition of Frequency Bias Setting but feels that the statement referenced provides further clarity and has decided to leave the definition as presently stated.</b></p> <p><b>The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the</b></p>		

Organization	Yes or No	Question 1 Comment
<p>ERO. This will be calculated as MW/0.1Hz.”</p> <p>The SDT agrees that using the phrase Reserve Sharing Group could cause confusion. The SDT has defined a new term “Frequency Response Sharing Group”. The definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p>		
Bonneville Power Administration	Yes	
Imperial Irrigation District	Yes	
SPP Standards Review Group	Yes	
Western Electricity Coordinating Council	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Energy Mark, Inc.	Yes	
Florida Power & Light Company	Yes	
FPL	Yes	
FMPP	Yes	

Organization	Yes or No	Question 1 Comment
Xcel Energy	Yes	
Tucson Electric Power	Yes	
NV Energy	Yes	
Cleco Corporation	Yes	
Great River Energy	Yes	

DRAFT

2. The SDT has made minor modifications to the Requirements R1 through R4 to provide additional clarity. Do you agree that these modifications provide sufficient clarity to comply with the standard? If not, please explain in the comment area.

**Summary Consideration:** The majority of the commenters felt that the use of an RSG as a method for supplying Frequency Response was not fully explained. The SDT modified the Background Document to further explain how an RSG (now FRSG) could be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”

Many of the commenters were concerned with the language in Requirement R3 stating that an entity had to be operating in Tie Line Bias mode unless there were adverse affects on the BES. The SDT removed this requirement from the proposed standard since it is duplicative of Requirement R6 and R7 in BAL-005-0.1b.

Many of the commenters did not agree with assigning the BA to provide Frequency Response. The NERC Functional Model and FERC cited the BA as the responsible party for providing Frequency Response. There are several different methods available to the BA to provide Frequency Response included in the Background Document.

A few of the commenters did not agree with lowering the minimum Frequency Bias Setting. Early research by Nathan Cohn on interconnected power system operations found that control is optimum if a BA’s Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased. The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in Attachment B. The attachment manages a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.

A couple of commenters were concerned that the BA could be responsible to supply an infinite amount of Frequency Response. They felt that a BA could not prepare for this in its planning process. The proposed standard was not clear on this subject and the SDT has added language in the “Event Selection Criteria” section of Attachment A to limit the amount of Frequency Response a BA would be required to provide to be compliant with the standard.

Organization	Yes or No	Question 2 Comment
Seattle City Light	Negative	<p>The language in Requirement 4 needs to be clarified and recommends the following change:</p> <p>R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either</p> <ul style="list-style-type: none"> <li>(i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or</li> <li>(ii) the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning]</li> </ul>
<p><b>Response: The SDT has modified Requirement R4 to use bullets in support of your suggestion.</b></p>		
Public Utility District No. 1 of Douglas County	Negative	<ol style="list-style-type: none"> <li>1. Recommend clarifying the language in R1 to include background information as to how RSGs fit into the FRM performance.</li> <li>2. Recommend R3 language be modified to permit operation in other than tie-line bias mode with the requirement to notify the RC.</li> <li>3. We have concern about the affect R3 will have on the WECC time error correction standard (BAL-004-WECC-1).</li> <li>4. Clarification is needed between Attachment A and the Background Document for projected peak and historical peak.</li> <li>5. We have a concern about the affect of lowering the minimum frequency bias obligation from 1% to .8% and its probable affect on reliability.</li> <li>6. We have a concern about he upper limit to the amount of frequency response expected from BAs.</li> </ol>
<p><b>Response: Comment 1 – The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes</b></p>		

Organization	Yes or No	Question 2 Comment
<p>that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>Comment 2 &amp; 3– The SDT has removed the Requirement R3 from the next version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.</p> <p>Comment 4 – The SDT has corrected the error between Attachment A and the Background Document.</p> <p>Comment 5 – Early research by Nathan Cohn<sup>2</sup> on interconnected power system operations found that control is optimum if a BA’s Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased.</p> <p>The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in Attachment B. The attachment manages a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations.</p> <p>Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting to be 0.9% of peak Load or generation and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations<sup>[MEL4]</sup>.</p> <p>Comment 6 – The SDT understands your concern and agrees that this could cause problems with compliance. The SDT has modified Attachment A to include language which puts an upper limit on the amount of Frequency Response required from an entity.</p>		
Potomac Electric Power Co.	Negative	<p>1)The proposed Requirements do not meet all the FERC directives.</p> <p>2)The proposed Requirements fail to recognize the fact that not all BAs can provide primary frequency response.</p> <p>3)The proposed Requirements are not all in the standard. Some are in the</p>

<sup>2</sup> *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

Organization	Yes or No	Question 2 Comment
		Attachments.
<p>Response: Comment 1 – The SDT disagrees with you about their meeting all of the FERC directives. Unfortunately your comment does not provide specific information as to what you believe is not being addressed. The SDT has included a section within the Background Document which details how this standard is meeting the FERC directives.</p> <p>Comment 2 – The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>Comment 3 – Unfortunately your comment does not provide enough information as to what parts of the attachments you believe should be in the requirements. However, the SDT has made significant modifications to both Attachment A and Attachment B. The SDT believes that the requirements should be succinct and the methodologies to be used should be part of an attachment.</p>		
Seattle City Light	No	<ul style="list-style-type: none"> <li>o LADWP and SCL have a concern with Requirement 3. The requirement should provide allowance for legitimate circumstances when an entity cannot run on Tie Line Bias mode and not have an Adverse Reliability Impact on the Balancing Authority’s Area. An entity should not be penalized when these legitimate circumstances occur. LADWP believes that the Frequency Response Standard Background Document, on Page 8, lists examples of legitimate circumstances:-</li> <li>Telemetry problems that lead the operator to believe ACE is significantly in error.-</li> </ul>



Organization	Yes or No	Question 2 Comment
		<p>The frequency input to AGC is not reflective of the BA’s true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection).- During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them).- For training purposes.- Many AGC systems will automatically switch to an alternate mode if the EMS determines Tie Line Bias control could lead to problems.</p> <ul style="list-style-type: none"> <li>o LADWP and SCL believe that the language in Requirement 4 needs to be clarified and recommends the following change (in red):R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) calculate the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning]</li> <li>o LADWP and SCL believes the language in Requirement 5 needs to be modified to be consistent with that of the second paragraph of Attachment B. SCL recommends the addition of “natural frequency response” as a third bullet item to Requirement 5 (in red). The revised requirement would read: <ul style="list-style-type: none"> <li>R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following: [Risk Factor: Medium ][Time Horizon: Operations Planning]</li> <li>o The minimum percentage of the Balancing Authority Area’s estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B.</li> <li>o The minimum percentage of the Balancing Authority Area’s estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment</li> </ul> </li> </ul>

Organization	Yes or No	Question 2 Comment
		<p>B.</p> <ul style="list-style-type: none"> <li>o The natural frequency response</li> </ul>
<p><b>Response: The SDT has removed the Requirement R3 from this version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.</b></p> <p><b>The SDT has modified Requirement R4 which now uses bullets in support of your suggestion.</b></p> <p><b>The SDT disagrees with your suggested modification. The SDT believes that your suggested modification could allow an entity to circumvent the minimum percentage process. However, the SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p>		
FMPP	No	<ul style="list-style-type: none"> <li>o R1. Each Balancing Authority (BA) or Reserve Sharing Group (RSG) shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each BA or RSG to maintain an adequate level of Frequency Response in the Interconnection. [Risk Factor: Medium ][Time Horizon: Operations Assessment] The BA does not have control over the frequency responsive generation. There needs to be a requirement that the GOP shall set frequency response for the generators as directed by the BA.</li> <li>o R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is <b>greater than or (&lt;= add these words) } {at least (&lt;= delete these words[MEL5]) }</b> equal to one of the following: [Risk Factor: Medium ][Time Horizon: Operations Planning]             <ul style="list-style-type: none"> <li>o The minimum percentage of the Balancing Authority Area’s estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B.</li> <li>o The minimum percentage of the Balancing Authority Area’s estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment B.</li> </ul> </li> </ul>

Organization	Yes or No	Question 2 Comment
<p>Response: The NERC <a href="#">Functional Model Technical Document</a> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>With regards to your comment concerning Requirement R5, you have not provided enough information for the SDT to respond. However, the SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</p>		
Western Electricity Coordinating Council	No	<p>Agree with the changes made to this latest version of BAL-003-1. However, additional clarity could be added by addressing the following:</p> <p>R1- It is not clear what is intended by "Reserve Sharing Group". As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly include an example in the background document to help explain how this would work.</p> <p>R3 - There may be occasions in which an entity has a legitimate reason or a need to operate in a mode other than Tie Line Bias but that does not qualify as an Adverse Reliability Impact. Recommend including language that would permit limited operation in a mode other than Tie Line Bias mode provided the Reliability Coordinator was notified. R3 - Has the drafting team considered whether or not the</p>

Organization	Yes or No	Question 2 Comment
		<p>language of Requirement R3 will have any conflict or coordination issue with the FERC-approved regional reliability standards BAL-004-WECC-1 - Automatic Time Error Correction?</p> <p>R5 - Suggest changing the language “at least equal to” to “greater than or equal to” for clarity<sup>[MEL6]</sup>.</p>
<p><b>Response:</b> The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>The SDT has removed the Requirement R3 from this version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.</p> <p>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. <u>The SDT believes we have implemented the intent of your suggestion.</u></p>		
Seattle City Light	Negative	<p>Answer: No Comments: o LADWP and SCL have a concern with Requirement 3. The requirement should provide allowance for legitimate circumstances when an entity cannot run on Tie Line Bias mode and not have an Adverse Reliability Impact on the Balancing Authority’s Area. An entity should not be penalized when these legitimate circumstances occur. LADWP believes that the Frequency Response Standard Background Document, on Page 8, lists examples of legitimate circumstances: - Telemetry problems that lead the operator to believe ACE is significantly in error. - The frequency input to AGC is not reflective of the BA’s true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection). - During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them). - For training purposes. - Many AGC systems will automatically switch to an alternate mode if the EMS determines Tie Line Bias control could lead to problems.</p>

Organization	Yes or No	Question 2 Comment
		<ul style="list-style-type: none"> <li>o LADWP and SCL believe that the language in Requirement 4 needs to be clarified and recommends the following change: R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning]</li> <li>o LADWP and SCL believes the language in Requirement 5 needs to be modified to be consistent with that of the second paragraph of Attachment B. SCL recommends the addition of “natural frequency response” as a third bullet item to Requirement 5. The revised requirement would read:  R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following: [Risk Factor: Medium ][Time Horizon: Operations Planning]</li> <li>o The minimum percentage of the Balancing Authority Area’s estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B.</li> <li>o The minimum percentage of the Balancing Authority Area’s estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment B.</li> <li>o The natural frequency response</li> </ul>
<p><b>Response: The SDT has removed the Requirement R3 from this version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.</b></p> <p><b>The SDT has modified Requirement R4 which now uses bullets in support of your suggestion.</b></p> <p><b>The SDT disagrees with your suggested modification. The SDT believes that your suggested modification could allow an entity to circumvent the minimum percentage process. However, the SDT has removed Requirement R5 and combined it into Requirement</b></p>		

Organization	Yes or No	Question 2 Comment
<b>R2 and a new Requirement R3.</b>		
Avista Corp.	Negative	<p>As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly including an example in the background document to help explain how this would work.</p> <p>Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.</p>
<p><b>Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</b></p> <p><b>Early research by Nathan Cohn<sup>3</sup> on interconnected power system operations found that control is optimum if a BA’s Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased.</b></p> <p><b>The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in Attachment B. The attachment manages a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations.</b></p> <p><b>Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting</b></p>		

<sup>3</sup> *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

Organization	Yes or No	Question 2 Comment
<p>to be 0.9% of peak Load or generation and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. <b>The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.</b></p>		
<p>City of Redding, Oregon Public Utility Commission, BrightSource Energy, Inc., Clark Public Utilities, Avista, Tri-State G &amp; T Association, Inc.; Deseret Power</p>	<p>Negative</p>	<p>As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly including an example in the background document to help explain how this would work.</p>
<p><b>Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</b></p>		
<p>Sacramento Municipal Utility District (SMUD)</p>	<p>No</p>	<p>As drafted, requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly including an example in the background document to help explain how this would work.</p> <p>As drafted, in requirement R3, each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that</p>

Organization	Yes or No	Question 2 Comment
		<p>does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired. Recommend including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified. We seek clarification from the drafting team as to whether or not there will be any conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction.</p>
<p><b>Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."</b></p> <p><b>The SDT has removed the Requirement R3 from the next version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.</b></p>		
Energy Mark, Inc.	No	<p>Comment 1: The timing requirements for implementing the Frequency Bias Setting are not specified for BAs participating in Overlap Regulation Service. The requirements indicate the value that should be used for the Frequency Bias Setting, but they do not indicate when those settings should be implemented.</p> <p>Comment 2: The term "Tie Line Bias mode" in Requirement R3 is not sufficiently defined to make this requirement enforceable. Any operating mode labeled as "Tie Line Bias mode" on an EMS that uses interchange scheduled and frequency error as inputs will meet the standard requirement as stated. This loop-hole exists because the NERC definition of "Tie Line Bias" fails to define the term in enough detail to actually limit AGC operation to the specified mode of operation. One way to improve this requirement would be to redefine Tie Line Bias in the NERC Glossary as a mode that uses the NERC ACE Equation as defined in BAL-001 as the basis for AGC action when the EMS is in Tie Line Bias mode.</p> <p>Comment 3: The standard is silent on how a BA receiving Overlap Regulation Service</p>



Organization	Yes or No	Question 2 Comment
		<p>should set its Frequency Bias Setting. Unless this is explicitly stated, it will be up to the auditors to determine the value of the Frequency Bias Setting for BAs receiving Overlap Regulation Service.</p> <p>Comment 4: In general, the requirements indicate what the responsible BAs should do and when. The requirements do not indicate what the BAs that are not responsible should do and when, ie. how they are relieved from responsibility. This may create problems when the auditors are required to interpret the standards for BAs that have appropriately shifted responsibilities to others.</p>
<p><b>Response: Comment 1 – The SDT believes that Requirement R2 states the timing for implementation of the Frequency Bias Setting. The Requirement R4 is simply to provide the BA with the method for combining the Frequency Bias Settings for providers of Overlap Regulation Service. The Background Document and Attachment A have also been modified to provide further clarity.</b></p> <p><b>Comment 2 – The SDT has removed the Requirement R3 from this version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.</b></p> <p><b>Comment 3 &amp; 4 – The SDT does not believe that there is an issue for entities receiving Overlap Regulation Service. However, the SDT has modified the Background document to further clarify this issue.</b></p>		
Duke Energy	No	<p>Duke Energy supports the concept of a group of BAs forming a group to share in Frequency Response however it should be clear that it is an option. We feel that the utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms which is specific to sharing of contingency reserves, and should be replaced with a new term, such as “Frequency Response Sharing Group”.</p> <p>R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in “Tie Line Bias” mode.</p> <p>Though comments are provided below on the Attachments, Duke Energy believes that all NERC Reliability Standards’ requirements must reside within the standard itself (which is vetted by the Industry and subject to FERC approval), and not within Attachments that may be revised without Industry review and approval. As noted</p>

Organization	Yes or No	Question 2 Comment
		<p>below and in prior comments, given the secondary control implications of changing the minimum Frequency Bias Setting (FBS), Duke Energy believes that subsequent revisions to the minimum FBS should be vetted through the Standards process. Duke Energy would suggest moving the details of the minimum FBS for each Interconnection into the Standard, and having the implementation plan include annual submittal of a revised minimum FBS based upon the methodology presented in Attachment B for ballot approval by the Industry.</p>
<p><b>Response:</b> The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it also believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>The SDT has removed the Requirement R3 from this version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.</p> <p>Attachments that are referenced within a Requirement are mandatory and enforceable.</p> <p>Early research by Nathan Cohn<sup>4</sup> on interconnected power system operations found that control is optimum if a BA’s Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased.</p> <p>The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in Attachment B. The attachment manages a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations.</p> <p>Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting to be 0.9% of peak Load or generation and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.</p>		

<sup>4</sup> *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

Organization	Yes or No	Question 2 Comment
<p>ISO/RTO Council Standards Review Committee</p>	<p>No</p>	<p>General Comments The SRC offers the following general comment with regard to the SDT’s proposed revisions: Gerry Cauley’s Results based initiative calls for requirements that focus on performance (i.e. WHAT must be accomplished NOT on WHY it is required or HOW it should be accomplished). The SRC has found that such explanatory statements as the SDT is proposing lead to ambiguities and confusion in the compliance application. Compliance Enforcement agents must consider not just the results but must decide if the action was taken for the given reason. To avoid such confusion, the Results based approach uses reference documents to address such background material while leaving the requirement as a direct mandate. The SRC notes:</p> <ul style="list-style-type: none"> <li>o All NERC Reliability Standards’ requirements must reside within the standard itself (which is vetted by the Industry and subject to FERC approval).</li> <li>o Data requirements are better handled through NERC’s Rules of Procedure Section 1600 than by mandating that ad hoc Forms be submitted.</li> <li>o Definitions should be generic, and should be self-contained (i.e. should not reference an external document).</li> <li>o The decisions regarding alternative methodologies should be decided by the Industry not by the SDT. The SDT should make its case and ask the Industry for its approval.</li> </ul> <p>Regarding Order 693 directives, the SRC notes that there are three directives as follows:</p> <ol style="list-style-type: none"> <li>(1) To include Levels of Non-Compliance;</li> <li>(2) To determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and</li> <li>(3) To define the necessary amount of Frequency Response needed for Reliable</li> </ol>

Organization	Yes or No	Question 2 Comment
		<p>Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.</p> <p>The SRC suggests that Directive 2 be handled directly as a mandate that the ERO conduct a fixed number of Frequency Response Surveys for randomly selected events. Discussion of the number and the methodology can be explained in a reference document and leave the specifics to the requirement.</p> <p>Directive 3 is critical to the Industry as it relates to who is the Applicable Entity. The SDT addresses Directive 3 by mandating Balancing Authorities meet an objective. The directive is to define that Objective, but there is no requirement associated with that Objective. There is an attachment and there are discussions of what “may” be done, but there is no requirement in the Standard itself. The reference to the BA as the provider of Frequency Response (i.e. Primary Control response) runs counter to other FERC directives that mandate obligated entities be able to self-serve or to interchange provision of services. In this case the BA per se has no assets and cannot self-serve, moreover the primary response service providers have no obligations to provide the service, thus the BA potentially could face a situation where there is no physical service to be purchased but there is a federally mandated standard to comply with. The idea of creating a Primary Response Market as some have proposed does not work without an obligation on some entity to physically provide that service.</p> <p>One final note, the SRC points out that the ACE is an error signal used to drive secondary response; it is not a signal to drive primary response. Thus the use of the Frequency Bias setting is not for control, it is for “adjusting” the error measure that is analyzed after the fact. This standard needs:</p> <ul style="list-style-type: none"> <li>o a requirement on the ERO to compute the Obligation on each Interconnection</li> <li>o a requirement on the ERO to conduct Frequency Response surveys (note the SRC does not support this requirement but believes that it is needed to meet the FERC directive)</li> </ul>

Organization	Yes or No	Question 2 Comment
		<p>o a requirement on energy supply assets (both generation and load) to provide primary response (as a function of the interconnection obligation in the first bullet) The above will allow NERC to comply with the FERC directives in a fashion consistent with the processes and procedures approved by FERC.</p> <p>Specific recommendations: The SRC proposes that R1 be deleted based on the facts that:</p> <ul style="list-style-type: none"> <li>o It imposes an obligation on an entity that has no capability to comply</li> <li>o There is an internal conflict with imposing penalties on a deterministic basis (compliance with a fixed set of events) for a statistical service (primary response is a function of the assets operating state and not a fixed service of the asset). In any case, all of the words after FRO should be deleted. The words are not needed for the requirement and if left in can become a source of contention between auditors and registered entities.</li> </ul> <p>R3 - delete the added phrase “mode to effectively coordinate control”. The phrase “would have an Adverse Impact on the BA’s area” needs further discussion. Who makes the decision that operating on AGC will have adverse impact must be defined.</p> <p>R5 - delete the phrase “In order to ensure control response”. Such phrases can be needless causes of debate. If a BA uses one of the bulleted methods but does not get “adequate response” then is the BA non-compliant? What is “adequate response”? Who decides if the response is adequate?</p>
<p><b>Response: Unfortunately your comment does not provide enough information as to what parts of the attachments you believe should be in the requirements. However, the SDT has made significant modifications to both Attachment A and Attachment B. The SDT believes that the requirements should be succinct and the methodologies to be used should be part of an attachment.</b></p> <p><b>The SDT is using defined forms to ensure that everyone calculates their Frequency Bias Setting and Frequency Response Measure in a consistent manner. The SDT also believes that this provides entities a relatively non-time consuming method to provide the necessary information to evaluate compliance.</b></p>		

Organization	Yes or No	Question 2 Comment
		<p>The SDT has modified the definitions to no longer reference any other documents.</p> <p>The SDT is recommending a certain approach to calculating the FRM. The reference to other methods being evaluated is simply a statement that the SDT believes that further analysis would be beneficial. Any modification to the calculation methodology would require industry approval.</p> <p>The SDT believes that it is meeting Directive #2 by requiring at least 20 events to be analyzed each year.</p> <p>The SDT believes that it is meeting the directive to define the “objective” by creating the BA Frequency Response Obligation (FRO). With regards to the BA being the responsible entity to provide Frequency Response the NERC <u>Functional Model Technical Document</u> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>The SDT has been instructed to include a “reliability outcome” within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.</p> <p>The ERO is not defined as an applicable entity in the industry approved SAR and therefore it would be inappropriate to include them as an applicable entity.</p>
Los Angeles Department of Water and Power	No	LADWP has a concern with Requirement 3. The requirement should provide allowance for legitimate circumstances when an entity cannot run on Tie Line Bias

Organization	Yes or No	Question 2 Comment
		<p>mode and not have an Adverse Reliability Impact on the Balancing Authority’s Area. An entity should not be penalized when these legitimate circumstances occur. LADWP believes that the Frequency Response Standard Background Document, on Page 8, lists examples of legitimate circumstances:- Telemetry problems that lead the operator to believe ACE is significantly in error.- The frequency input to AGC is not reflective of the BA’s true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection).- During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them).- For training purposes.- Many AGC systems will automatically switch to an alternate mode if the EMS determines Tie Line Bias control could lead to problems.</p> <p>LADWP believes that the language in Requirement 4 needs to be clarified and recommends the following change:- R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning]</p> <p>LADWP believes the language in Requirement 5 needs to be modified to be consistent with that of the second paragraph of Attachment B. LADWP recommends the addition of “natural frequency response” as a third bullet item to Requirement 5. The revised requirement would read:- R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following: [Risk Factor: Medium ][Time Horizon: Operations Planning]</p> <ul style="list-style-type: none"> <li>o The minimum percentage of the Balancing Authority Area’s estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B.</li> <li>o The minimum percentage of the Balancing Authority Area’s estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as</li> </ul>

Organization	Yes or No	Question 2 Comment
		<p>specified by the ERO in accordance with Attachment B. o The natural frequency response</p>
<p><b>Response: The SDT has removed the Requirement R3 from the next version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.</b></p> <p><b>The SDT has modified Requirement R4 which now uses bullets in support of your suggestion.</b></p> <p><b>The SDT disagrees with your suggested modification. The SDT believes that your suggested modification could allow for an entity to circumvent the minimum percentage process. However, the SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p>		
<p>MidAmerican Energy Co.</p>	<p>Negative</p>	<p>MidAmerican supports the comments provided by the NSRF.</p> <p>It is not clear if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard.</p> <p>It is not clear what will happen if an event occurs in the Eastern Interconnection that causes the frequency to drop to less than 59.6 Hz (e.g. what if freq dips to 59.5). Without a statement that the BA is expected to keep its allocated portion of generation reserves only up to the largest event identified in Table 2, a BA could be expected to provide limitless amounts of frequency response. Balancing Authorities cannot know what is expected of them and therefore cannot plan appropriately [MEL7]. [r8]</p>
<p><b>Response: The SDT understands your concern and has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</b></p>		
<p>East Kentucky Power Coop.; ACES Power Marketing; Hoosier Energy Rural Electric Cooperative, Inc.; Southwest Transmission Cooperative,</p>	<p>Negative</p>	<p>Overall, [we] believes the drafting team has done an excellent job to address the FERC directives from Order 693. However, we believe there is still room for improving the standard and that there is a significant technical error. The technical error was introduced by applying Requirement 1 to the RSG and is discussed below. Requirement 1 should not apply to a Reserve Sharing Group. Reserve Sharing Groups</p>



Organization	Yes or No	Question 2 Comment
Inc.		<p>(RSG) are designed to share Contingency Reserves and/or Operating Reserves not Frequency Response. While these reserves may be frequency responsive, they are not being shared for the purpose of expanding frequency response. Furthermore, while reserve sharing groups may calculate a joint ACE by summing its individual BA ACE values, RSGs do not have a Frequency Bias Setting which is necessary to assess a Frequency Response Obligation.</p> <p>Under item 3 of the Event Selection Criteria section, the delta F and Point C should be described either in this attachment or the “Frequency Response Standard Background Document”. While many in industry may understand what these terms mean, history has a way of getting lost with personnel turnover. Furthermore, this would help ensure that the auditors and industry have a duplicate understanding.</p> <p>In the Frequency Response Obligation section on page 2, several items require more description. Further description of why an N-2 event was chosen for the Contingency Protection Criteria should be provided and which N-2 event was selected so that industry can help validate if the correct MW value was selected.</p> <p>Furthermore, the document should clarify if the Contingency Protection Criteria contains the “safety margin”. There is a statement in the paragraph before the table that states it does, but then the table lists out a separate 25% “Safety Margin”. Thus, it is not clear if the “Safety Margin” is included in the Contingency Protection Criteria value listed in the table or not. “Safety margin” should be changed to “reliability margin”. Safety has a specific meaning in the electric industry and its use here is not appropriate. The Base Obligation should be explained. The explanation should include its purpose and origin.</p> <p>The Data Retention section requires the BA to retain data or evidence for up to four years. No data that exceeds the audit cycle should be required to be retained. The audit cycle is three years for BAs.</p>

**Response: The SDT agrees that using the term “Reserve Sharing Group” could cause confusion and has defined a new term “Frequency Response Sharing Group (FRSG)”. The new definition reads “A group whose members consist of two or more**

Organization	Yes or No	Question 2 Comment
<p>Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>The SDT agrees with your comment concerning further clarification on certain terms and has made significant modifications to the Background Document and Attachments A and B.</p> <p>The Data Retention is stated as “the current year plus three calendar years” since it is highly unlikely that an entity will be audited exactly three years after its previous audit. The SDT recognizes that most audits will occur within the year following the third year.</p>		
<p>PPL Electric Utilities Corp.;</p> <p>PPL Generation LLC</p>	<p>Negative</p>	<p>The PPL Companies do not support proposed Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) primarily because PPL believes it inappropriately subjects Reserve Sharing Groups (RSGs) to the proposed requirements. The proposed Applicability provision states that the mandatory reliability requirements would be applicable to (1) Balancing Authorities and (2) Reserve Sharing Groups (where applicable). However, it is unclear how the proposed requirements would be applicable to an RSG. RSGs typically do not provide a mechanism for sharing automatic Frequency Response. The BA Frequency Response Obligation (FRO) is a formula based on BAs and the Interconnection and has nothing to do with RSGs. Rather, RSGs collectively respond to requests for activation of contingency reserves generally after the request is made by a member Balancing Authority. The Standard Drafting Team should therefore remove RSGs from the Applicability section and should remove all other references to RSGs in the proposed standard.</p>
<p>Response: The SDT disagrees that an RSG is not an appropriate mechanism for providing Frequency Response. However the SDT does believe that using the term “Reserve Sharing Group” could cause confusion and has defined a new term “Frequency Response Sharing Group (FRSG)”. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine</p>		

Organization	Yes or No	Question 2 Comment
<p>how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</p> <p>FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul>		
Progress Energy	No	<p>PGN supports the collective comments of SERC members. We feel that the utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as “Frequency Response Sharing”.</p> <p>R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in “Tie Line Bias” mode</p>
<p><b>Response: The SDT agrees that using the term “Reserve Sharing Group” could cause confusion and has defined a new term “Frequency Response Sharing Group (FRSG)”. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</b></p> <p><b>The SDT has removed the requirement to operate AGC in Tie Line Bias mode as this requirement was duplicative of the Requirements R6 and R7 in BAL-005-0.1b.</b></p>		
MRO NSRF	No	<p>R1- It is not clear what is intended by "Reserve Sharing Group" in this context. As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly include an example in the background document to help explain how this would work.</p> <p>R2 - Please add the word “range” in-between the words “date” and “specified”. The background document specifies that there is a 72-hour period to implement the FBS</p>

Organization	Yes or No	Question 2 Comment
		<p>setting (See Background document Page 7). R2, as written, does not reflect the period for which an entity may implement the ERO validated Bias into ACE. Also see our comment on #7 as to the length of the comment period. Question 7 comment is provided to assist the SDT; Note from question 7: (Page 7 (3rd paragraph) of the Background document states “Given the fact that BA’s can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date.</p> <ol style="list-style-type: none"> <li>1. The Standard itself does not state this provision (24 hour window on each side of target date) as indicated.</li> <li>2. The SDT accurately addresses the fact that BA’s could have EMS or staffing issues during implementation of the ERO validated FBS. The current stated 72-hour window is not long enough for implementation of the FBS as there may be a host of issues that could impact implementation. We suggest that a seven day window be used for implementation of the FBS.)</li> </ol> <p>R3 - Recommend the term “Adverse Reliability Impact” be removed from Requirement</p> <ol style="list-style-type: none"> <li>3. Based on the NERC definition of the term, a smaller entity could never operate its AGC outside of TLB mode due to their impact on the BES not likely to result in “instability or Cascading”. To ensure a more consistent and equitable approach when applying this Requirement, recommend the drafting team incorporate the reliability reasons listed within the Background Document into the actual Requirement. Additionally, the phrase “effectively coordinated control” should be removed as this is not essential to the Requirement and introduces ambiguity in its application. To this end, the following revisions are proposed:</li> </ol> <p>R3. Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact</p>

Organization	Yes or No	Question 2 Comment
		<p>on the Balancing Authority’s Area meets one or more of the following conditions.</p> <ul style="list-style-type: none"> <li>o Telemetry problems that lead the operator to believe ACE is significantly in error.</li> <li>o The frequency input to AGC is not reflective of the BA’s true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection).</li> <li>o During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them).</li> <li>o For training purposes.</li> <li>o Many AGC systems will automatically switch to an alternative mode if the EMS determines Tie Line Bias control could lead to problems.</li> <li>o For single BA Interconnections, Flat Frequency and Tie Line Bias are equivalent.</li> <li>o The Reliability Coordinator has been informed and the duration is [insert time constraint language here].</li> </ul> <p>R5 - Recommend to delete the phrase “In order to ensure control response”. Such phrases can be needless causes of debate. If a BA uses one of the bulleted methods but does not get “adequate response” then is the BA non-compliant? What is “adequate response”? Who decides if the response is adequate? Please clarify.</p>
<p><b>Response: The SDT agrees that using the term “Reserve Sharing Group” could cause confusion and has defined a new term “Frequency Response Sharing Group (FRSG). The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</b></p> <p><b>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</b></p> <p><b>FRSG performance may be calculated on one of two ways:</b></p>		

Organization	Yes or No	Question 2 Comment
<ul style="list-style-type: none"> <li>Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.</li> </ul> <p>The SDT has modified Requirement R2 to provide better clarity. The requirement now reads "Each Balancing Authority not receiving Overlap Regulation Service and utilizing a fixed frequency Bias Setting shall implement the Frequency Bias Setting determined subject to Attachment B and validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and use it until a different Frequency Bias Setting is to be implemented to ensure effectively coordinated Tie Line Bias control."</p> <p>The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p> <p>The SDT has been instructed to include a "reliability outcome" within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.</p>		
Xcel Energy	No	<p>R1- It is not clear what is intended by "Reserve Sharing Group" in this context. As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly include an example in the background document to help explain how this would work.</p> <p>R3 - recommend modifying the language to permit AGC out of TLB mode if the RC is notified; also remove the "to ensure coordinated control" as this is not essential for the requirement. Our reasoning behind the suggested change to notification of the RC is that there are occasions where an entity would need to perform testing, etc and it could be argued that testing would not be sufficient justification for meeting the Adverse Reliability Impact definition. Here is proposed revised language: Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode, unless the Balancing Authority's Reliability Coordinator has been informed and the duration is [insert time constraint language here].</p>
<p><b>Response: The SDT agrees that using the term "Reserve Sharing Group" could cause confusion and has defined a new term</b></p>		

Organization	Yes or No	Question 2 Comment
<p><b>“Frequency Response Sharing Group (FRSG)”. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</b></p> <p><b>The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</b></p>		
<p>Constellation Energy Commodities Group</p>	<p>No</p>	<p>R1 should accommodate agreements between multiple BAs and RSGs in achieving the annual Frequency Response Measure. See proposed modification below:</p> <p>R1. Each Balancing Authority shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligations (FRO) to ensure that sufficient Frequency Response is provided by each BA. Either the Balancing Authority individual FRM, multiple Balancing Authority’s FRM per written agreement, or the FRM of the Reserve Sharing Group must be equal to or more negative than the applicable Frequency Response Obligations (FRO) for a single Balancing Authority or the aggregate of multiple Balancing Authorities or RSGs.-</p> <p>In R2, “Each Balancing Authority not participating in Overlap Regulation Service” should state “Each Balancing Authority, not receiving Overlap Regulation, shall implement the appropriate Frequency Bias Setting (fixed or variable,) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control”. –</p> <p>In R3, the explanatory language about why to operate in Tie Line Bias mode should be deleted. See proposed modification below:</p> <p>R3. Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode, unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area.-</p> <p>R5 should be modified to state only that the FBS is specified by the ERO in accordance with Attachment B. As drafted the Requirement is in conflict with Attachment B because the Requirement mandates a minimum and does not allow</p>

Organization	Yes or No	Question 2 Comment
		<p>for a reduction to the minimum but it references Attachment B which is titled “Process for Adjusting Minimum Frequency Bias Setting”. See proposed modification below:</p> <p>R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is as specified by the ERO in accordance with Attachment B.-</p> <p>There should be a Requirement specifically stating there is an obligation to complete and submit FRS Form 1 by January 10th each year for clarity.-</p> <p>The requirements should be re-ordered to reflect the chronology of the process for frequency calculation, implementation and performance measurement. The recommended order is as follows:</p> <ul style="list-style-type: none"> <li>R5 which defines the minimum Frequency Bias Setting (FBS) for a Balancing Authority</li> <li>R4 which describes how the minimum FBS may be altered through Overlap Regulation Service</li> <li>R2 which identifies the coordination required around implementation</li> <li>R3 which requires operation in Tie Line Bias mode</li> <li>R1 which establishes the performance obligation</li> </ul>
<p><b>Response:</b> The SDT does not see anything within the Requirement that would restrict any agreements between multiple BAs and RSGs. However, the SDT has modified the language in Requirement R1 to provide additional clarity. The requirement now reads “Each Balancing Authority (BA) or Frequency Response Sharing Group (FRSG) shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A, and calculated and reported in accordance with the methods and formats specified in Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each BA or FRSG to maintain an adequate level of Frequency Response in the Interconnection.” The SDT has also defined a new term “Frequency Response Sharing Group (FRSG)” because it also believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources</p>		



Organization	Yes or No	Question 2 Comment
		<p>required to jointly meet the Frequency Response Obligations of its members.”</p> <p>The SDT has modified Requirement R2 to provide better clarity. The requirement now reads “Each Balancing Authority not receiving Overlap Regulation Service and utilizing a fixed frequency Bias Setting shall implement the Frequency Bias Setting determined subject to Attachment B and validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and use it until a different Frequency Bias Setting is to be implemented to ensure effectively coordinated Tie Line Bias <span style="border: 1px solid red; padding: 2px;">control</span><sup>[MEL9]</sup>.”.</p> <p>The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p> <p>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT also believes that Attachment B only details the process the ERO is to use when evaluating and making modifications to the minimum Frequency Bias Setting.</p> <p>The SDT disagrees with your comment concerning an additional requirement for timing of reporting. The SDT believes that this is an administrative issue and is better handled within an attachment. The SDT would also like to note that an attachment when referenced in a requirement becomes mandatory and enforceable.</p> <p>The SDT thanks you for your suggested ordering for the requirements but believes that the revised proposed standard reflects the proper order in that it sets the goal at beginning of year, calculates performance, reports performance and calculates bias at the end of the year.</p>
Constellation Energy	Negative	<p>-R1 should accommodate agreements between multiple BAs and RSGs in achieving the annual Frequency Response Measure. See proposed modification below: R1. Each Balancing Authority shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligations (FRO) to ensure that sufficient Frequency Response is provided by each BA. Either the Balancing Authority individual FRM, multiple Balancing Authority’s FRM per written agreement, or the FRM of the Reserve Sharing Group must be equal to or more negative than the applicable Frequency Response Obligations (FRO) for a single Balancing Authority or the aggregate of multiple Balancing Authorities or RSGs.</p> <p>-In R2, “Each Balancing Authority not participating in Overlap Regulation Service”</p>

Organization	Yes or No	Question 2 Comment
		<p>should state “Each Balancing Authority, not receiving Overlap Regulation, shall implement the appropriate Frequency Bias Setting (fixed or variable,) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control”.</p> <p>-In R3, the explanatory language about why to operate in Tie Line Bias mode should be deleted. See proposed modification below: R3. Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode, unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area.</p> <p>-R5 should be modified to state only that the FBS is specified by the ERO in accordance with Attachment B. As drafted the Requirement is in conflict with Attachment B because the Requirement mandates a minimum and does not allow for a reduction to the minimum but it references Attachment B which is titled “Process for Adjusting Minimum Frequency Bias Setting”. See proposed modification below: R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is as specified by the ERO in accordance with Attachment B.</p> <p>-There should be a Requirement specifically stating there is an obligation to complete and submit FRS Form 1 by January 10th each year for clarity. -The requirements should be re-ordered to reflect the chronology of the process for frequency calculation, implementation and performance measurement. The recommended order is as follows: R5 which defines the minimum Frequency Bias Setting (FBS) for a Balancing Authority R4 which describes how the minimum FBS may be altered through Overlap Regulation Service R2 which identifies the coordination required around implementation R3 which requires operation in Tie Line Bias mode R1 which establishes the performance obligation</p>
<p><b>Response: The SDT does not see anything within the Requirement that would restrict any agreements between multiple BAs and RSGs. However, the SDT has modified the language in Requirement R1 to provide additional clarity. The requirement now reads</b></p>		

Organization	Yes or No	Question 2 Comment
		<p>“Each Balancing Authority (BA) or Frequency Response Sharing Group (FRSG) shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A, and calculated and reported in accordance with the methods and formats specified in Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each BA or FRSG to maintain an adequate level of Frequency Response in the Interconnection.” The SDT has also defined a new term “Frequency Response Sharing Group (FRSG)” because they also believed that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>The SDT has modified Requirement R2 to provide better clarity. The requirement now reads “Each Balancing Authority not receiving Overlap Regulation Service and utilizing a fixed frequency Bias Setting shall implement the Frequency Bias Setting determined subject to Attachment B and validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and use it until a different Frequency Bias Setting is to be implemented to ensure effectively coordinated Tie Line Bias control.”.</p> <p>The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p> <p>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT also believes that Attachment A only details the process the ERO is to use when evaluating and making modifications to the minimum Frequency Bias Setting.</p> <p>The SDT disagrees with your comment concerning an additional requirement for timing of reporting. The SDT believes that this is an administrative issue and is better handled within an attachment. The SDT would also like to note that an attachment when referenced in a requirement becomes mandatory and enforceable.</p> <p>The SDT thanks you for your suggested ordering for the requirements but believes that the revised proposed standard reflects the proper order in that it sets the goal at beginning of year, calculates performance, reports performance and calculates bias at the end of the year.</p>
Ameren	No	R1.While we agree with the concept of the entire requirement and the determination of the Interconnection Frequency Response Obligation, we believe that the accurate measurement of individual BA's FRM has not yet been demonstrated. This requirement should not be part of the standard (even with the additional 12 months in the effective date) until the field trial demonstrates that

Organization	Yes or No	Question 2 Comment
		<p>each BA's FRM can be consistently calculated to a level that will not create false non-compliance to this requirement. While the calculation methodology in FRS Form 1 looks promising, with the A-value and B-value average periods, we believe successful completion of the field trial is prudent.</p> <p>R5. We were not sure if it was intended for this comment question to include Requirement R5, but have decided to include our comments here. While we agree with the requirement of R5, it should not be at the expense of changing the value of L10 in BAL-001, R2, which has been accepted by FERC in Order 693. An accommodation should be made so that any changes to the Frequency Bias Setting according to BAL-003, R5, should not affect the value of L10 used in BAL-001, R2.</p>
<p><b>Response: The SDT agrees that validation of the methodology needs to occur. However, the SDT is working under a FERC approved deadline for completion of this project. The SDT is recommending that continued analysis should occur during the filing period and implementation period of the standard. The STD has also added considerable language to the Background Document on why it has chosen the methodology it is recommending for this standard.</b></p> <p><b>The SDT understands your concern with the reduction of the minimum Frequency Bias Setting affecting other performance standards. That is why the SDT is proposing a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations.</b></p> <p><b>Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting to be 0.9% of peak Load or generation and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.</b></p>		
American Electric Power	No	<p>R1: Clarification is needed regarding the responsibility of a BA that is a member of a Reserve Sharing Group.</p> <p>R2 and R3: What does “coordinated control” mean?</p> <p>There no leverage for the BA to require the generator to carry their burden of addressing governor settings or droop settings, yet the BA is obligated to meet some</p>

Organization	Yes or No	Question 2 Comment
		<p>performance measures.</p> <p>This revision adds new performance measure responsibilities on the BA who likely has no direct control over every resource affecting their performance within their footprint. We are not necessarily challenging the performance measures themselves, nor their underlying objectives, however AEP views this as a gap in responsibilities which potentially effects reliability.</p>
<p><b>Response:</b> The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” to eliminate any confusion with the present d3efined term “Reserve Sharing Group”. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</p> <p>FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul> <p>The SDT has been instructed to include a “reliability outcome” within the requirements and therefore included the language “...coordinated control...”. The SDT understands that this does not provide any additional clarity for complying with the requirement and could be removed. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.</p> <p>The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p> <p>The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators</p>		

Organization	Yes or No	Question 2 Comment
<p>or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p>		
Great River Energy	No	<p>R1: Including the Reserve Sharing Group (RSG) in the Frequency Response Obligation is outside of the boundaries of a RSG. Where or how would a Frequency Bias be determined for an RSG to determine their Frequency Response Obligation? Although it is apparent that frequency responds during the implementation of reserves, the intention of a RSG is not to share frequency response, but rather to share Reserves. Additionally, if the Frequency Response Obligation is not met by the RSG how are penalties assessed? Should they be assessed to the group as a whole or strictly to the generators that did not meet their individual obligation?</p> <p>R3: Needs to include verbiage for those circumstances when it would be necessary to run AGC out of TLB such as during necessary testing. The BA should have the option to operate out of TLB for a predetermined amount of time if needed when notification and coordination with the RC has been established.</p>
<p>Response: The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary</p>		

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<p>organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</p> <p>FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul> <p>The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.</p> <p>The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p>		
Tucson Electric Power	No	<p>R1: TEP feels that the FRO should be able to be calculated by the BA and that Form 1 changes should be treated via the Standard drafting process.</p> <p>R2: TEP feels that use Form 1 should be required by the Standard. Further, BAs should calculate its own frequency bias setting without ERO intervention.</p> <p>R3: Operating outside Tie Line Bias mode should be allowed during a year to allow for the testing of other modes.</p> <p>R4: Agree with the concept, but without ERO intervention.</p> <p>R5: Should read "greater than or equal to[MEL10]".</p>
<p>Response: The FRO can be estimated by the BA but the actual BA FRO for compliance is based on the BA’s footprint and is a function of the Interconnection FRO. Modifications to the FRS Form 1 would go through the Standard Drafting Process.</p> <p>R3 - The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p> <p>R2 and R4 - The Frequency Bias Setting is calculated on FRS Form 1. The ERO is only validating the data used in the calculation. This is a practice that exists today. History has shown that there typically are errors in the data.</p>		

Organization	Yes or No	Question 2 Comment
<p><b>R5 - The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p>		
SCE&G	Affirmative	<p>R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in “Tie Line Bias” mode.</p> <p>o We suggest the SDT consider a term other than “Initial’ in the title for Table 1. We suggest “Proposed Frequency Bias Setting” for Table 1 o</p>
<p><b>Response: The requirement to operate AGC in Tie Line Bias mode has been removed from the standard since it was duplicative of Requirements R6 and R7 in BAL-005-0.1b.</b></p> <p><b>The SDT has modified Attachment B to address your concern. The new title is, “Frequency Bias Setting Minimums”.</b></p>		
Bonneville Power Administration	No	<p>Regarding R1, BPA believes that adding additional requirements in R1 by referencing Attachment A does not add clarity. FRO should be a calculation that the BA’s can do themselves and included within the standard.</p> <p>Can Form 1 be changed outside of the standard drafting process? BPA doesn’t believe that Form 1 should be allowed to be changed outside of the standard drafting process. As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO).</p> <p>As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards ‘secondary response’. BPA recommends clarifying this concept and possibly including an example in the background document to help explain how this would work.</p> <p>Regarding R2, BPA believes each BA should be able to calculate its own frequency bias setting without ERO validation. The standard can require the BA to use Form 1, if the BA doesn’t use Form 1 correctly, then the BA would be in violation of the standard.</p>



Organization	Yes or No	Question 2 Comment
		<p>BPA believes that R3 should include a minimal amount of time (suggesting a couple of hours per year) to allow for testing other modes. Requirement R3 requires each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired. BPA recommends including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified. BPA seeks clarification from the drafting team as to whether or not there will be any conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction.</p> <p>BPA agrees with the concept of R4, however, BPA again disagrees with the ERO validation of the frequency bias setting.</p> <p>BPA believes that reducing frequency bias obligation is detrimental to reliability. It seems that lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. BPA believes that over time, it would seem that this pattern would lead to poorer response.</p> <p>BPA believes that R5 should read “greater than or equal to one of the following” not “at least equal to”. The requirement should be a part of Form 1 or included in R2. For variable bias, the minimum percentage should be based on the forecasted month peak.</p>
<p><b>Response: R1 – The FRO can be estimated by the BA but the actual BA FRO for compliance is based on the BA’s footprint and is a function of the Interconnection FRO.</b></p> <p><b>Modifications the FRS Form 1 would go through the Standard Drafting Process.</b></p> <p><b>The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined</b></p>		

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		<p>term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</p> <p>FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul> <p>The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.</p> <p>R2 – The SDT is interested in the use of good data for the calculations but does not believe that a BA should be penalized for minor data errors. This is why the SDT proposes that the ERO validate the data. In addition, this process is used today.</p> <p>R3 - The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p> <p>R4 – Again, this is a process that is in use today. The SDT is not proposing that the ERO modify anything, just proposing that the ERO validate the data being supplied.</p> <p>R5 - The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. However, the SDT understands your concern with the reduction of the minimum Frequency Bias Setting affecting other performance requirements. The SDT is proposing a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations.</p> <p>Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting to be 0.9% of peak Load or generation and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.</p>

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	No	<p>Regarding R1:</p> <ol style="list-style-type: none"> <li>1. Neither R1 nor the referenced Attachment A clarifies the FRM requirements for an RSG to comply versus a BA. In particular               <ol style="list-style-type: none"> <li>(i) At p.3, Attachment A states that the ERO is responsible for “annually assigning an FRO and Frequency Bias Setting to each BA.” No mention is made of RSGs.</li> <li>(ii) Attachment A only references RSGs in the context of reporting obligations for Form 1 (at p.4) and</li> <li>(iii) Compared to BAL-002-0 R1.1, which clearly states that the BA may elect to fulfill its obligation through an RSG and that in such cases the RSG has the same responsibilities as each BA (that is a participant in the RSG).</li> </ol> </li> <li>2. It should be clarified that this requirement applies to a BA, where the BA doesn’t belong to an RSG, OR to an RSG. As it is currently drafted, the standard applies to each BA and each RSG. It is redundant in that each BA would need to comply, whether or not they are a member of an RSG that would also be required to comply. Further, the NERC Glossary definition of an RSG is a group of BAs that collectively maintain, allocate and supply operating reserves. No mention is made of the agreement including the sharing or delegation of responsibility related to FRM. Accordingly, the standard should only reference a BA being able to delegate responsibility to an RSG if the RSG Agreement allows for such delegation.</li> <li>3. R1 does not specify where or how the FRO is determined. Presumably this would be determined by the ERO pursuant to Attachment A.</li> <li>4. The phrase “to ensure that sufficient Frequency Response ...” should be separated from the requirement as it is               <ol style="list-style-type: none"> <li>(i) not descriptive of the required actions;</li> <li>(ii) redundant with the stated purpose at the beginning of the standard. In</li> </ol> </li> </ol>

Organization	Yes or No	Question 2 Comment
		<p>general, such a drafting technique should be avoided as it may allow Responsible Entities to argue that a violation has not occurred where the specific action that is described has not been taken, but the purpose referenced in the requirement has been met.</p> <p>Regarding R2:</p> <ol style="list-style-type: none"> <li>1. It is not clear from R2 who determines the Frequency Bias Setting for “validation” by the ERO and how the FBS is determined. (Presumably done by the BA in accordance with Attachment B). Based on Background document, should refer to those “published” by ERO. The BA’s FBS may not be validated, and may be modified before posting.</li> <li>2. Attachment B does not refer to the ERO “validating” FBS.</li> <li>3. Attachment B refers to an RSG calculating FBS, but the standard does not.</li> </ol>
<p><b>Response: R1 – Comment 1 &amp; 2 – The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</b></p> <p><b>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</b></p> <p><b>FRSG performance may be calculated on one of two ways:</b></p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul> <p><b>The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency</b></p>		

Organization	Yes or No	Question 2 Comment
<p>Response<sup>[MEL11]</sup>.</p> <p>Comment 3 – The process for determining the FRO is detailed in Attachment A.</p> <p>Comment 4 – The SDT has been instructed to include a “reliability outcome” within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.</p> <p>R2 – Comment 1 – The Frequency Bias Setting is calculated on FRS Form 1. The ERO is only validating the data not calculating the setting. The ERO will be working with the BA to correct any data errors discovered during the validation process. This is a process that is in use today</p> <p>Comment 2 &amp; 3 – The SDT has made significant modifications to the Background Document, Attachment A and Attachment B to provide additional clarity<sup>[MEL12]</sup>. <b>Procedure states validating – RSG is no longer referenced for FBS</b></p>		
<p>NV Energy</p>	<p>No</p>	<p>Requirement 1 seems to be the only one that has any applicability to an RSG; however, it is unclear under what circumstances this requirement applies to an RSG. Suggest changing the R1 to be addressed solely to BA's or alternatively, explain under Applicability section 1.2 what "where applicable" means.</p>
<p>Response: The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</p> <p>FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul>		

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<p>The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.</p>		
<p>ACES Power Marketing Standards Collaborators</p>	<p>No</p>	<p>Requirement 1 should not apply to a Reserve Sharing Group. Reserve Sharing Groups (RSG) are designed to share Contingency Reserves and/or Operating Reserves not Frequency Response. While these reserves may be frequency responsive, they are not being shared for the purpose of expanding frequency response. Furthermore, while reserve sharing groups may calculate a joint ACE by summing its individual BA ACE values, RSGs do not have a Frequency Bias Setting which is necessary to assess a Frequency Response Obligation.</p>
<p><b>Response:</b> The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</p> <p>FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul> <p>The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.</p>		
<p>City of Redding, Oregon Public Utility Commission, BrightSource Energy, Inc.,</p>	<p>Negative</p>	<p>Requirement R3 requires each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area. There may be</p>

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Clark Public Utilities, Avista, Tri-State G & T Association, Inc.; Deseret Power		occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired. Recommend including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified.
<p><b>Response: The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</b></p>		
Alberta Electric System Operator	No	<p>The language used in the requirements is superfluous. This could result in confusion and incorrect assumptions being made.</p> <p>In R1, the comment within brackets “(as detailed in Attachment A and calculated on FRS Form 1)”, is not necessary as it is already part of the FRM definition. We suggest removing this bracketed text from the requirement.</p> <p>Also in R1, the phrase “to ensure that sufficient Frequency Response is provided by each BA or RSG to maintain an adequate level of Frequency response in the Interconnection” is a high level objective that does not add clarity to this requirement. We suggest removing this from the requirement.</p> <p>R2, R3 and R5 use similar language e.g. “to ensure effectively coordinated Tie Line Bias control”, “to ensure adequate control response” etc. Although it provides background information, this does not add clarity to the requirement. We suggest removing these from the requirements.</p>
<p><b>Response: Based on industry comments the SDT has modified the definition for FRM such that it no longer references any other documents. Therefore, the SDT believes that leaving the reference to Attachment in the standard is prudent, based on advice from the standards staff – without a reference to the specific Attachment, the responsible entity can’t be held to compliance with the performance identified in that attachment.</b></p> <p><b>The SDT has been instructed to include a “reliability outcome” within the requirements and therefore included the language you are referencing. The SDT understands that this does not provide any additional clarity for complying with the requirement and could be removed. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for</b></p>		

Organization	Yes or No	Question 2 Comment
<b>consideration.</b>		
Hydro-Quebec TransEnergie	No	The objective of R2 is that all BA’s implement their new Bias Setting at the same time, based on the previous year’s data, so that control stays the most effective throughout the Interconnection (Tie-Line Bias). In addition, the new Bias will be in effect all year long. The process is quite simple and straightforward for a fixed Bias Setting. As for Variable Bias Setting, this process is not applicable before the fact since the Bias equation can depend on real-time values that are not known in advance. In addition, the simultaneous Bias implementation is not an issue for a single BA Interconnection. Therefore, we suggest that Requirement 2 applies only to Fixed Bias Setting.
<b>Response: The SDT agrees with your comment and has modified Requirement R2 to reflect your concern. The SDT has also added an addition Requirement R3 to address entities using a variable Frequency Bias Setting.</b>		
Northeast Power Coordinating Council	No	The requirements should not be directed at Balancing Authorities, as generators are the main supplier of “discretionary” frequency response. Requirement R1 refers to an attached form, which is not part of the standard and therefore not enforceable.
<p><b>Response: The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</b></p> <p><b>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</b></p> <p><b>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</b></p>		



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<p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>If an attachment is referenced in a requirement that attachment becomes part of the requirement. <u>Does not refe form</u></p>		
<p>Beaches Energy Services; City of Bartow, Florida; Tampa Electric Co.</p>	<p>Negative</p>	<p>The standard is silent on the “methods to obtain Frequency Response”. For instance, the BA does not have authority over governor and other generator settings. There should be a requirement for GOPs to incorporate setting changes directed by the BA, otherwise the standard establishes requirements that BAs may not have the authority to achieve. R1 includes the Reserve Sharing Group in its applicability, but none of the other requirements do.</p> <p>There is no consideration of "footprint" changes of the BA resulting in different allocation from the ERO during a year. The standard and Attachments seem to specify an annual process with due dates in December and January with no allowance for mid-year changes and associated allocation changes.</p> <p>If a standard has a requirement for the ERO, who will audit the ERO for compliance? If the ERO does not meet its obligations, can an entity still be found non-compliant, especially on a schedule basis? Wasn't there an issue of assigning standards to RROs, e.g., the fill-in-the-blank standards? Are there similar issues with assigning requirements to the ERO? Is the ERO a “user, owner or operator” of the BPS under Section 215, e.g., at (b)(1)”... All users, owners and operators of the bulk-power system shall comply with the reliability standards that take effect under this section.” I question how this would work from a compliance perspective.</p> <p>On R5, the wording should be changed from “absolute value is at least equal to” to “absolute value is greater than or equal to”</p>
<p><b>Response:</b> The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p>		

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<p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>The SDT has also included other methods that a BA can use to provide Frequency Response in the Background Document.</p> <p>The SDT has added language to Attachment A to address changes in a BAs footprint.</p> <p>The proposed standard is not putting a requirement on the ERO. There is language in the Attachments to provide additional time for a BA to become compliant if the ERO is late in providing the necessary information. If the ERO does not provide the necessary information then the BA would not be required to modify anything and therefore the last information provided would be that which would be used for compliance purposes.</p> <p>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3<sup>[MEL13]</sup>.</p>		
<p>South Carolina Electric and Gas</p>	<p>No</p>	<p>The utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as “Frequency Response Sharing”.</p> <p>R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in “Tie Line Bias” mode.</p>
<p>Response: The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p>		

Organization	Yes or No	Question 2 Comment
<p>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</p> <p>FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul> <p>The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.</p> <p>The SDT has removed the requirement to operate AGC in Tie Line Bias mode as this requirement was duplicative of the Requirements R6 and R7 in BAL-005-0.1b.</p>		
<p>Tri-State G &amp; T Association, Inc.; Tucson Electric Power Co.; U.S. Army Corps of Engineers; South California Edison ; Platte River Power Authority; Pacific Gas and Electric Company; Colorado Springs Utilities; Idaho Power Company; California Energy Commission; California ISO; Deseret Power</p>	<p>Negative</p>	<p>We believe that there are several modifications that, if implemented to the existing requirements, would result in an improved, clarified standard.</p> <p>As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly including an example in the background document to help explain how this would work.</p> <p>Requirement R3 requires each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired.</p>

Organization	Yes or No	Question 2 Comment
		<p>Recommend including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified. We seek clarification from the drafting team as to whether or not there will be any conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction.</p>
<p><b>Response:</b> The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</p> <p>FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul> <p>The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.</p> <p>The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p>		
ISO New England Inc	No	<p>We do not agree with placing a requirement on Balancing Authorities, as generators are the main supplier of “discretionary” frequency response. Also, the requirement refers to an attached form, which is not part of the standard and therefore not enforceable.</p>
<p><b>Response:</b> The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency</p>		

Organization	Yes or No	Question 2 Comment
<p>Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>If an attachment is referenced in a requirement that attachment becomes part of the requirement.</p>		
<p>SERC OC Standards Review Group</p>	<p>No</p>	<p>We feel that the utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as “Frequency Response Sharing”.</p> <p>R2 exempts BAs participating in Overlap Regulation Service from implementing the Frequency Bias Setting on the date specified by the ERO, and R4 states how the BA performing Overlap Regulation Service will modify its Frequency Bias Setting but does not state when the setting will be implemented. The exemption for BAs participating in Overlap Regulation Service should either be deleted from R2 or language stating the implementation date of the frequency bias setting needs to be included in R4.</p> <p>R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in “Tie Line Bias” mode.</p>

Organization	Yes or No	Question 2 Comment
		<p>Response: The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p> <p>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</p> <p>FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul> <p>The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.</p> <p>The SDT has modified the language in Requirement R2. The term “not participating in” has be replace with “not receiving”. This now encompasses entities that are providing Overlap Regulation Service.</p> <p>The SDT has removed the requirement to operate AGC in Tie Line Bias mode as this requirement was duplicative of the Requirements R6 and R7 in BAL-005-0.1b.</p>
<p>Florida Municipal Power Agency/JEA Electric Compliance</p>	<p>No</p>	<p>We thank the SDT for their hard work and diligence in moving this Project forward. However, we have some concerns that cause us to not support the standard in its current form.</p> <p>In general, we believe that there has not been sufficient prudency review for the standard, especially R1, to justify a performance based standard around a Frequency Response Measure.</p> <p>We also believe that the proposed standard does not meet all of the conditions of</p>

Organization	Yes or No	Question 2 Comment
		<p>the Final SAR and Supplemental SAR. The “Final SAR” was to develop methods by which a performance based standard would eventually be developed. The Final SAR states: “The proposed standard’s intent is to collect data needed to accurately model existing Frequency Response. There is evidence of continuing decline in Frequency Response in the three Interconnections over the past 10 years, but no confirmed reason for the apparent decline. The proposed standard requires entities to provide data so that Frequency Response in each of the Interconnections can be modeled, and the reasons for the decline in Frequency Response can be identified. Once the reasons for the decline in Frequency Response are confirmed, requirements can be written to control Frequency Response to within defined reliability parameters.” BAL-003-1 does not seem to complete the scope of this “Final SAR”. For instance, “the reasons for the decline in Frequency Response” were not confirmed to our knowledge; and the field trial is not completed to our knowledge. The Supplemental SAR adds to the scope of the Final SAR: “To provide a minimum Frequency Response Obligation for the Balancing Authority to achieve, methods to obtain Frequency Response and provide a consistent method for calculating the Frequency Bias Setting for a Balancing Authority. In addition, the standard will specify the optimal periodicity of Frequency Response surveys.” The Supplemental SAR does not eliminate the pre-requisite contained in the Final SAR to determine the reasons for the decline in frequency response and confirm them before establishing “defined reliability parameters”.</p> <p>In addition, the standard does not complete the requirement of the Supplemental SAR to identify “methods to obtain Frequency Response”. For instance, neither the BA nor the RSG have authority over governor and other generator settings. There should be a requirement for GOPs to incorporate setting changes directed by the BA, otherwise the standard establishes requirements that BAs and RSGs may not have the authority to achieve.</p> <p>There is no consideration of “footprint” changes of the BA resulting in different allocation from the ERO during a year. The standard and Attachments seem to specify an annual process with due dates in December and January with no</p>

Organization	Yes or No	Question 2 Comment
		<p>allowance for mid-year changes and associated allocation changes.</p> <p>If a standard has a requirement for the ERO, who will audit the ERO for compliance? If the ERO does not meet its obligations, can an entity still be found non-compliant, especially on a schedule basis? Wasn't there an issue of assigning standards to RROs, e.g., the fill-in-the-blank standards? Are there similar issues with assigning requirements to the ERO? Is the ERO a "user, owner or operator" of the BPS under Section 215, e.g., at (b)(1)" ... All users, owners and operators of the bulk-power system shall comply with the reliability standards that take effect under this section." We question how this would work from a compliance perspective.</p>
<p><b>Response:</b> The SDT is responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012.</p> <p>The SDT agrees that the original SAR was strictly for data collection. However, a supplemental SAR was developed to address the FERC March 18, 2010 Order and was subsequently approved by the industry. The Standards Committee has determined that a proposed standard must be within the scope of the approved SAR but the proposed standard is not required to address the full scope of the SAR if stakeholders support a reduced scope.</p> <p>The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p>		



Organization	Yes or No	Question 2 Comment
<p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>The SDT has also included other methods that a BA can use to provide Frequency Response in the Background Document.</p> <p>The SDT has added language to Attachment A to address changes in a BA's footprint.</p> <p>The proposed standard is not putting a requirement on the ERO. There is language in the Attachments to provide additional time for a BA to become compliant if the ERO is late in providing the necessary information. If the ERO does not provide the necessary information then the BA would not be required to modify anything and therefore the last information provided would be that which would be used for compliance purposes.</p>		
Imperial Irrigation District	Yes	
SPP Standards Review Group	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Florida Power & Light Company	Yes	
Independent Electricity System Operator	Yes	
Associated Electric Cooperative Inc	Yes	
Cleco Corporation	Yes	
Keen Resources Asia Ltd.	Yes	

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

**Summary Consideration:** The majority of the commenters agreed with the VRFs that the SDT has proposed for the requirements within the standard.

One commenter felt the VRFs were too high and that they should have a “lower” VRF. The SDT developed the VRFs using the NERC Violation Risk Factor guidelines approved by FERC. A lower VRF is an administrative type of requirement that, if violated would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Violation of any of the requirements in the proposed standard could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.

Another commenter stated that they could not find the “Risk Severity Levels” in the standard. The SDT is not sure as to the meaning of this comment. The SDT believes that the commenter may have been mixing two different terms, Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). The question asked by the SDT was concerning the VRFs. These are located within the body of the Requirement. The VSLs are located towards the end of the proposed standard.

Organization	Yes or No	Question 3 Comment
Seattle City Light	Negative	Answer: Yes. Comments: LADWP and SCL agree with the following VRFs: - R1 - Medium - R2 - Medium - R3 - Medium - R4 - Medium - R5 - Medium
<b>Response: The SDT thanks you for your clarifying comment.</b>		
Energy Mark, Inc.	No	Comment 5: See comments in the non-binding poll.
<b>Response: Please see our response to your comments from the non-binding poll.</b>		
Florida Power & Light Company	No	Could not find the Risk Severity Levels in the documents.

Organization	Yes or No	Question 3 Comment
<p>Response: The SDT is not sure as to the meaning of your comment. The SDT believes that you may be mixing two different terms, Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). The question asked by the SDT was concerning the VRFs. These are located within the body of the Requirement. The VSLs are located towards the end of the proposed standard.</p>		
Cleco Corporation	No	Please note Cleco does not use the VRFs therefore we feel too much energy and time is spent on the VRFs. The SDT needs to concentrate on the requirements and measurements.
<p>Response: The SDT thanks you for your clarifying comment.</p>		
Ameren	No	This is problematic since for a single BA interconnection these could be argued to be appropriate VRFs, but is different for a multiple BA interconnection, where the risk that a single BA would pose to the interconnection would be Lower.
<p>Response: The SDT developed the VRFs using the NERC Violation Risk Factor guidelines approved by FERC. This document can be found at <a href="http://www.nerc.com/files/Violation_Risk_Factors.pdf">http://www.nerc.com/files/Violation_Risk_Factors.pdf</a>. IA lower VRF is an administrative type of requirement that, if violated not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Violation of any of the requirements in the proposed standard could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.</p>		
Seattle City Light/Los Angeles Department of Water and Power	Yes	LADWP and SCL agree with the following VRFs:- R1 - Medium- R2 - Medium- R3 - Medium- R4 - Medium- R5 - Medium
<p>Response: The SDT thanks you for your affirmative response and clarifying comment.</p>		
NV Energy	Yes	Medium appears to be reasonable and appropriate.
<p>Response: The SDT thanks you for your affirmative response and clarifying comment.</p>		

Organization	Yes or No	Question 3 Comment
Bonneville Power Administration	Yes	
Imperial Irrigation District	Yes	
Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC OC Standards Review Group	Yes	
SPP Standards Review Group	Yes	
ISO/RTO Council Standards Review Committee	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Progress Energy	Yes	
Southern Company	Yes	
FMPP	Yes	

Organization	Yes or No	Question 3 Comment
ISO New England Inc	Yes	
Tucson Electric Power	Yes	
Independent Electricity System Operator	Yes	
Associated Electric Cooperative Inc	Yes	
American Electric Power	Yes	
South Carolina Electric and Gas	Yes	
Manitoba Hydro	Yes	
Constellation Energy Commodities Group	Yes	
Great River Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Duke Energy	Yes	
Keen Resources Asia Ltd.	Yes	

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

**Summary Consideration:** Many of the commenters were concerned with the language in Requirement R3 stating that an entity had to be operating in Tie Line Bias mode unless there were adverse affects on the BES and that if the requirement was modified that the measure should be modified. The SDT explained that it had removed this requirement from the proposed standard since they felt it was duplicative of Requirement R6 and R7 in BAL-005-0.1b.

Some commenters objected to the definition for FRM and the Measure referencing another document (FRS Form 1). The SDT explained that it modified the definition for FRM to no longer reference another document. The revised definition reads “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.”

A couple of the commenters had concerns with Requirement R5 in that it should reference “natural Frequency Response” as a third bullet. The SDT has explained that it removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3 [MEL14].

Some commenters indicated that the use of an RSG as a method for supplying Frequency Response was not fully explained. The SDT modified the Background Document to further explain how an RSG (now FRSG) could be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”

A couple commenters wanted the sampling interval to be tuned on a per Interconnection basis to support HQTE’s characteristics. The SDT agreed and explained that it adjusted the event selection criteria to address concerns related to response driving frequency back to pre-event level during the B value measurement period and this adjustment should address their concern.

Organization	Yes or No	Question 4 Comment
Seattle City Light	Negative	Answer: No. Comments: LADWP and SCL recommend that the Measures for Requirement 3 and Requirement 5 reflect their comments to Question 2.

Organization	Yes or No	Question 4 Comment
<p>Response: The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p>		
<p>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</p>		
<p>Constellation Energy Commodities Group</p>	<p>No</p>	<p>Based on language modifications proposed to the Requirements, the measures should be revisited.</p>
<p>Response: The SDT has revised the Measures to align with modifications made to the Requirements.</p>		
<p>Xcel Energy</p>	<p>No</p>	<p>Based on our suggested changes to R3 in response to Question 2, the drafting team should modify M3 to be consistent with the proposed language.</p>
<p>Response: The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p>		
<p>MRO NSRF</p>	<p>No</p>	<p>Based on suggested changes to R3 in response to Question 2, the drafting team should modify M3 to be consistent with the proposed language.</p> <p>Additionally, M1 should be revised to not reference a specific Form. The Form may be the format of choice but it should not be an implied requirement.</p> <p>Measures 3 and 4 identify the use of “operating logs” as evidence. Measure 2 identifies hard copy and electronic evidence, “or other evidence”. We suggest calling out specifically “operator logs” for M2 also, in case there are system problems in capturing hard copy or electronic evidence during the short time window for implementation.</p>
<p>Response: The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</p>		
<p>The SDT has modified Measure M1 which no longer references a form but does reference Attachment A to align with the requirement.</p>		
<p>The SDT is only providing examples (“...such as...”) of what could be used to reflect compliance. Other evidence can be used as long as it reflects compliance with the standard.</p>		



Organization	Yes or No	Question 4 Comment
Bonneville Power Administration	No	BPA believes that historian data should be able to be used for evidence.
<p><b>Response: The SDT is only providing examples (“...such as...”) of what could be used to reflect compliance. Other evidence can be used as long as it reflects compliance with the standard. The SDT believes that the data from the software program “Historian” could be used to demonstrate compliance.</b> [MEL15].</p>		
Manitoba Hydro	No	<p>It should be clarified that R1 requirement applies to a BA, where the BA doesn’t belong to an RSG, or to an RSG. As it is currently drafted, the standard applies to each BA and each RSG. It is redundant in that each BA would need to comply, whether or not they are a member of an RSG that would also be required to comply.</p> <p>Further, the NERC Glossary definition of an RSG is a group of BAs that collectively maintain, allocate and supply operating reserves. No mention is made of the agreement including the sharing or delegation of responsibility related to FRM. Accordingly, the standard should only reference a BA being able to delegate responsibility to an RSG if the RSG Agreement allows for such delegation.</p>
<p><b>Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response</b> [MEL16].</p> <p>The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p>		
Tucson Electric Power	No	It should be clear that historical data may be used to show compliance.
<p><b>Response: The SDT is only providing examples (“...such as...”) of what could be used to reflect compliance. Other evidence can be used as long as it reflects compliance with the standard. The SDT believes that the data used to reflect compliance would have to be historical data.</b></p>		

Organization	Yes or No	Question 4 Comment
Seattle City Light/ Los Angeles Department of Water and Power	No	LADWP and SCL recommend that the Measures for Requirement 3 and Requirement 5 reflect their comments to Question 2.
<p><b>Response: The SDT has removed Requirement R3 as it is duplicative of Requirements R6 &amp; R7 in BAL-005-0.1b.</b></p> <p><b>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p>		
ISO/RTO Council Standards Review Committee	No	<p>M1: The measure should not be tied to a specific Form. If a BA has the evidence but does not provide it on a given Form, how is the reliability of the Power System impacted? The Form may be the format of choice but it should not be an implied requirement.</p> <p>M4: This measure does not read quite right. Something seems to be missing in the part that says: "...showing when Overlap Regulation Service is provided including Frequency Bias Setting calculation to demonstrate compliance with Requirement R4." This part might have read something like: "...showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation or it calculated the Frequency Bias Setting meeting the conditions specified in Requirement R4."</p>
<p><b>Response: The SDT has modified Measure M1 which no longer references a form, however it does reference Attachment A to align with the associated requirement.</b></p> <p><b>The SDT is only providing examples ("...such as...") of what could be used to reflect compliance. Other evidence can be used as long as it reflects compliance with the standard.</b></p> <p><b>The SDT has modified the Measure M4 to incorporate your suggested wording.</b></p>		
Independent Electricity System Operator	No	M4: This measure does not read quite right. Something seems to be missing in the part that says: "...showing when Overlap Regulation Service is provided including Frequency Bias Setting calculation to demonstrate compliance with Requirement R4."

Organization	Yes or No	Question 4 Comment
		This part might have read something like: "...showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation or it calculated the Frequency Bias Setting meeting the conditions specified in Requirement R4."
<b>Response: The SDT has modified the Measure M4 to incorporate your suggested wording.</b>		
ERCOT	No	Measure should be modified to align with revised Requirements per ERCOT's comments on #1.
<b>Response: The SDT has modified the Measures to align with the modifications to the Requirements.</b>		
SERC OC Standards Review Group/ Progress Energy/ South Carolina Electric and Gas/ Duke Energy	No	See comments in Question 2 regarding utilization of the term "Reserve Sharing Group".
<b>Response: Please see our response to your comments on Question 2 regarding "Reserve Sharing Group".</b>		
Northeast Power Coordinating Council/ISO New England Inc.	No	The sampling interval needs to be tuned on a per Interconnection basis to support HQTE's characteristics.
<b>Response: The SDT adjusted the event selection criteria to address concerns related to response driving frequency back to pre-event level during the B value measurement period. We believe that this adjustment addresses your concern.</b>		
Florida Power & Light Company	No	What is meant by documented formulae for M5? Is a one time snapshot of the AGC formula sufficient? The concept is ok but this needs clarification of proof.
<b>Response: The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b>		
Southwest Power Pool	Yes	Measures are more specific and measurable than seen in the past. This is a positive

Organization	Yes or No	Question 4 Comment
Regional Entity		improvement.
<b>Response: The SDT thanks you for your affirmative response and clarifying comment.</b>		
Ameren	Yes	With the understanding that any suggested changes to the proposed requirements would come with corresponding changes to their measure.
<b>Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT agrees that any modification to a Requirement would necessitate a re-evaluation of the corresponding Measure.</b>		
Imperial Irrigation District	Yes	
SPP Standards Review Group	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Salt River Project	Yes	
Energy Mark, Inc.	Yes	
FMPP	Yes	
Associated Electric Cooperative Inc	Yes	
NV Energy	Yes	
Cleco Corporation	Yes	
Great River Energy	Yes	

Organization	Yes or No	Question 4 Comment
Hydro-Quebec TransEnergie	Yes	
Keen Resources Asia Ltd.	Yes	

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

**Summary Consideration:** Most of the commenters indicated that VSLs for Requirement R1 should not include language tied to whether or not a BA is in a single BA Interconnection or a multi-BA Interconnection. Frequency Response is an Interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA’s performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections<sup>[MEL17]</sup>.

Several commenters did not agree with the VSLs for Requirement R3. The SDT removed Requirement R3 from the revised standard since the requirement was duplicative of Requirement R6 & R7 in BAL-005-0.1b.

With concerns about the use of the RSG as a means to provide Frequency Response, the SDT modified the Background Document to further explain how an RSG (now FRSG) could be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”

Organization	Yes or No	Question 5 Comment
Seattle City Light	Negative	Answer: No. Comments: LADWP and SCL recommend that either the VSL for Requirement 3 reflects its comments to Question 2, or that these comments be addressed as an exception in the Measure for Requirement 3.
<p><b>Response: Based on Industry comments and further review, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.</b></p>		

Organization	Yes or No	Question 5 Comment
Public Utility District No. 1 of Douglas County	Negative	1. The BA and interconnection meet the FRO differently. Suggest removing the interconnection performance from the VSL and develop additional levels of BA failure to meet its FRO.
<p><b>Response:</b> The drafting team does not agree, but believes an explanation would be helpful.</p> <p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p> <p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections [MEL18].</p>		
BrightSource Energy, Inc.	Negative	The negative vote from BrightSource is related to the proposed VSL only. The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO. Conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.
<p><b>Response:</b> The drafting team does not agree, but believes an explanation would be helpful.</p> <p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p>		

Organization	Yes or No	Question 5 Comment
<p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p>		
<p>U.S. Army Corps of Engineers; Platte River Power Authority; Pacific Gas and Electric Company; Idaho Power Company; Colorado Springs Utilities; California Energy Commission; California ISO; Clark Public Utilities; Tucson Electric Power Co.; Tri-State G &amp; T Association, Inc.</p>	<p>Negative</p>	<p>The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO. Conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.</p>
<p><b>Response:</b> The drafting team does not agree, but believes an explanation would be helpful.</p> <p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p> <p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p>		
<p>Kansas City Power &amp; Light Co.</p>	<p>Negative</p>	<p>The VSL for Requirement 3 does not sufficiently reflect a thoughtful range of</p>



Organization	Yes or No	Question 5 Comment
		violation severity of duration or number of instances by which AGC is not in Tie-Line Bias mode.
<p><b>Response:</b> Based on Industry comments and further review, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.</p>		
<p>ACES Power Marketing; East Kentucky Power Coop.; Hoosier Energy Rural Electric Cooperative, Inc.</p>	<p>Negative</p>	<p>The VSLs on for Requirement R1 set a previously un-established precedent of relying on the performance of other registered entities to establish the severity level of the violation. This is not appropriate. The VSLs should be rewritten to provide further gradations of the violation severity based on the BA’s own performance.</p>
<p><b>Response:</b> The drafting team does not agree, but believes an explanation would be helpful.</p> <p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation’s impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p> <p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA’s performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p>		
<p>Southwest Transmission Cooperative, Inc.</p>	<p>Negative</p>	<p>The VSLs on for Requirement R1 set a previously un-established precedent of relying on the performance of other registered entities to establish the severity level of the violation. This is not appropriate. The VSLs should be rewritten to provide further gradations of the violation severity based on the BA’s own performance. The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the</p>

Organization	Yes or No	Question 5 Comment
		<p>interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO. Conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.</p>
<p>Response: The drafting team does not agree, but believes an explanation would be helpful.</p>		
<p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p>		
<p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p>		
<p>Western Area Power Administration</p>	<p>Negative</p>	<p>Under compliance for R1, there is a difference between VSL levels whether the interconnection met is FRO or not. If the interconnection meets it's FRO but a single BA doesn't't meet its share of FRO the violation is considered low VSL, but, if the interconnection dosen't't meet it's FRO the same BA will have a High VSL. Obligation of the individual BA to meet its allocated FRO should always be applicable regardless of what other BAs are doing in the interconnection. This provision creates a disparity amongst BAs and creates a disparate treatment between the BAs who perform compared to those who don't.</p>
<p>Response: The drafting team does not agree, but believes an explanation would be helpful.</p>		
<p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p>		
<p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's</p>		

Organization	Yes or No	Question 5 Comment
<p>performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p>		
<p>Ameren Services; Ameren Energy Marketing Co./Ameren</p>	<p>Negative/No</p>	<p>It is not clear how the VSL for R1 uses the "Summation of the BA's FRM", when the requirement is BA or RSG specific.</p>
<p>Response: Based on comments, the drafting team has created a new definition for an entity called a Frequency Response Sharing Group (FRSG). FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.</li> </ul>		
<p>Manitoba Hydro</p>	<p>Negative/No</p>	<p>The Violation Severity Levels for R1 penalize entities more severely depending on how the interconnection as a whole has performed. MH believes that BAs should only be held accountable for issues within their control and that the VSLs for R1 should be revised accordingly.</p>
<p>Response: The drafting team does not agree, but believes an explanation would be helpful.</p> <p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p> <p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p>		

Organization	Yes or No	Question 5 Comment
Constellation Energy Commodities Group	No	The language in the VSLs for R1 should be revisited based on the proposed language modifications above and should also clearly look to the FRM of a BA, group of BAs or RSG against the BA FRO not an Interconnection FRO.
<p><b>Response: The drafting team has made conforming changes to VSLs based on wording changes to the Requirements.</b></p> <p><b>Regarding the evaluation of the Interconnection, the drafting team does not agree, but believes an explanation would be helpful.</b></p> <p><b>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation’s impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</b></p> <p><b>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA’s performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</b></p> <p><b>The “Lower” and “Medium” VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.</b></p> <p><b>Based on comments, the drafting team has created a new definition for an entity called a Frequency Response Sharing Group (FRSG). FRSG performance may be calculated on one of two ways:</b></p> <ul style="list-style-type: none"> <li><b>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</b></li> <li><b>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</b></li> </ul>		
Bonneville Power	No	BPA believes that R1 needs to be more clear and concise as to what is being conveyed in the requirement. It is difficult to understand. The proposed VSLs for

Organization	Yes or No	Question 5 Comment
Administration		<p>Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO. BPA believes that conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.</p>
<p><b>Response:</b> The “Lower” and “Medium” VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively. We would welcome suggested wording changes that relay this concept more clearly.</p>		
<p>With regard to removing a view of Interconnection performance, the drafting team does not agree, but believes an explanation would be helpful.</p>		
<p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation’s impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p>		
<p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA’s performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p>		
Florida Power & Light Company	No	<p>For R1 the low and high level descriptions appear to be identical and the high level is less than the medium risk level.</p> <p>For R3 there should be low, medium, and high levels. One BA not operating to TLB does not jepordize the Interconnection. Additionally, computer failures, database loads etc may require some period where TLB is not in service. Suggestion would</p>

Organization	Yes or No	Question 5 Comment
		<p>be Lower VSL operation off of TLB for more than 5 but &lt; 8 continuous hours or accumulative during the year of more than 8 &lt; 16 hours. Medium VSL would be operation off of TLB for more than 8 but &lt;16 continuous hours or accumulative during the year of more than 16 &lt;24 hours. High VSL would be operation off of TLB for more than 16 &lt;24 continuous hours or accumulative during the year of more than 36 &lt;48 hours. Severe VSL would be &gt;24 continuous hours off of TLB or accumulative of &gt; 48.</p>
<p><b>Response:</b> The “Lower” and “Medium” VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.</p> <p>Based on Industry comments and further review, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.</p>		
NV Energy	No	<p>For R1, suggest that the VSL's not be dependent upon the aggregate performance of the BA's within an interconnection.</p>
<p><b>Response:</b> The drafting team does not agree, but believes an explanation would be helpful.</p> <p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p> <p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p>		
American Electric Power	No	<p>It is not clear for R1 what the exact delineations are among Lower, Medium, High, and Severe VSL's.</p>
<p><b>Response:</b> The “Lower” and “Medium” VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are</p>		

Organization	Yes or No	Question 5 Comment
<p>deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.</p>		
Seattle City Light	No	LADWP and SCL recommend that either the VSL for Requirement 3 reflects its comments to Question 2, or that these comments be addressed as an exception in the Measure for Requirement 3.
<p><b>Response: Based on Industry comments and further review, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.</b></p>		
Los Angeles Department of Water and Power	No	LADWP recommends that either the VSL for Requirement 3 reflects its comments to Question 2, or that these comments be addressed as an exception in the Measure for Requirement 3.
<p><b>Response: Based on Industry comments and further review, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.</b></p>		
ReliabilityFirst	No	<p>ReliabilityFirst thanks the SDT for their effort on this project. ReliabilityFirst has a number of concerns/questions related to the draft BAL-003-1 VSLs which include the following:</p> <ol style="list-style-type: none"> <li>1. General VSL Comment - For consistency with other standards, each VSL should begin with the phrase "The Responsible Entity..." or "The Balancing Authority". This is consistent with the language of the requirement and correctly pinpoints the appropriate responsible entity.</li> <li>2. VSL R1 Comment - Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement". ReliabilityFirst suggests the following modification:               <ol style="list-style-type: none"> <li>a. Lower VSL - The Responsible Entity achieved an annual FRM within an Interconnection that was equal to or more negative than the Interconnection's FRO and the Responsible Entity's FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz,</li> </ol> </li> </ol>

Organization	Yes or No	Question 5 Comment
		<p>whichever one is the greater deviation from its FROb. Medium VSL - The Responsible Entity achieved an annual FRM within an Interconnection that was equal to or more negative than the Interconnection’s FRO and the Responsible Entity’s FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever one is the greater deviation from its FROc. High VSL - The responsible entity failed to achieve an annual FRM that is equal to or more negative than its FRO and the Responsible Entity’s, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FROd. Severe VSL - The responsible entity failed to achieve an annual FRM that is equal to or more negative than its FRO and the Responsible Entity’s FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO3.</p> <p>VSL R4 Comment - Based on the FERC Guideline #3 “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement”. ReliabilityFirst suggests the following modification:</p> <p>a. Example for Lower VSL which should be carried throughout all four VSLs - The Balancing Authority incorrectly modified the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than 5% of the validated or calculated value4.</p> <p>VSL R5 Comment - Based on the FERC Guideline #3 “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement”. ReliabilityFirst suggests the following modification:</p> <p>a. Example for Lower VSL which should be carried throughout all four VSLs - The Balancing Authority used a monthly average Frequency Bias Setting whose absolute value was less than or equal to 5% below the minimum specified by the ERO.</p>
<p><b>Response:</b> While there may be a better way to lay out the VSL, the VSL for R1 is consistent with R1 in that performance can be reported either as a single BA or as an RSG. The “Lower” and “Medium” VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection</p>		



Organization	Yes or No	Question 5 Comment
<p>does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.</p> <p>The drafting team has modified the VSLs for R4 based on your comments. The SDT removed Requirement R5 and combined it into revised Requirement R2 and new Requirement R3.</p>		
<p>Progress Energy / South Carolina Electric and Gas/Duke Energy</p>	<p>No</p>	<p>See comments in Question 2 regarding utilization of the term “Reserve Sharing Group”.</p>
<p>Response: Based on comments, the drafting team has created a new definition for an entity called a Frequency Response Sharing Group (FRSG).</p> <p>Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRFSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.</p> <p>FRSG performance may be calculated on one of two ways:</p> <ul style="list-style-type: none"> <li>• Calculate a group NI<sub>A</sub> and measure the group response to all events in the reporting year on a single FRS Form 1, or</li> <li>• Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that sums each participant’s individual annual performance.</li> </ul>		
<p>SERC OC Standards Review Group</p>	<p>No</p>	<p>See comments in Question 2 regarding utilization of the term “Reserve Sharing Group”.</p> <p>VSL for R1:The draft VSLs for R1 uses the summation of FRM for all BAs within an Interconnection as a factor in determining the applicable VSL. This does not seem consistent with R1. R1 is about a single BA and the individual BA’s frequency response performance as measured by the FRM for that specific BA. Including the FRM summation of the Interconnection expands R1. It appears that a BA that is</p>

Organization	Yes or No	Question 5 Comment
		<p>non-compliant with R1 could end up with either a Low/Medium or High/Severe VSL based upon the FRO performance of the Interconnection. The FRM performance of the Interconnection is beyond the knowledge and control of a single BA and should not be a determinate of the applicable VSL. Is there a technical basis for selection of the 1%, 30% and 15MW/.1 Hz VSL breakpoints? Does the Lower VSL give a 1% dead band to a BA's FRO? If so, will this be acceptable to NERC/FERC?</p> <p>VSL for R2: The VSL should reflect the language used in the requirement. R2 says a BA "not participating in Overlap Regulation service shall ....", while the VSL says a BA "not receiving Overlap Regulation Service....." The VSL language is not consistent with the requirement [MEL19].</p> <p>VSLs for R5: Since Frequency Bias Setting is expressed as a negative value, the terms "absolute value" and "less than" must be used carefully. Wouldn't the "absolute value" of a BA's Frequency Bias Setting always be positive and thus it could never be less than the minimum specified by the ERO (a negative value)?</p>
<p>Response: With regard to R1, VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p>		
<p>The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.</p>		
<p>Regarding the 1%, 30% and 15MW breakpoints, the 1% value accommodates rounding error. The 30% or 15MW/0.1Hz is intended to comparably address both large and small BAs. The drafting team used its judgment in selecting these values and cannot predict what the FERC might accept.</p>		
<p>[MEL20]</p>		
Western Electricity	No	The proposed VSLs for Requirement R1 treat a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the

Organization	Yes or No	Question 5 Comment
Coordinating Council		FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO.
<p>Response: The drafting team does not agree, but believes an explanation would be helpful.</p>		
<p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation’s impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p>		
<p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA’s performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response.</p>		
<p>To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p>		
<p>The “Lower” and “Medium” VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.</p>		
JEA Electric Compliance/ MRO NSRF	No	The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO.
<p>Response: The drafting team does not agree, but believes an explanation would be helpful.</p>		

Organization	Yes or No	Question 5 Comment
<p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation’s impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p>		
<p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA’s performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response.</p>		
<p>To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p>		
<p>The “Lower” and “Medium” VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.</p>		
<p>Northeast Power Coordinating Council</p>	<p>No</p>	<p>The violation severity levels for R1 are reasonable. The technical writing needs to be enhanced for clarity.</p>
<p><b>Response: Thank you for the comment. The drafting team will look at ways to clarify the wording or provide an explanation in the Background Document.</b></p>		
<p>ISO New England Inc</p>	<p>No</p>	<p>The violation severity levels for R1 seem to be reasonable. However, the technical writing needs to be enhanced for clarity</p>
<p><b>Response: Thank you for the comment. The drafting team will look at ways to clarify the wording or provide an explanation in the Background Document.</b></p>		
<p>SPP Standards Review Group/Cleco Corporation</p>	<p>No</p>	<p>The VSLs for R2 are based on 5, 15 and 25 days. What was the justification for these values? Could we just as well use 10, 20 and 30 or some other set of values?  In R3, we understand that brief periods of operation outside of TLB control are</p>

Organization	Yes or No	Question 5 Comment
		<p>allowable providing 1) continued operation in TLB control would create ARI on the Interconnection or 2) that justification is provided for the periods when TLB is not used. For example, if something happens within our EMS that disables TLB control are we compliant if we document the period as an EMS malfunction?</p>
<p><b>Response:</b> Regarding R2, the time windows were based on judgment of the drafting team. Similar to the commenters' question, the team could have chosen 1, 7, 14 and 28 days or 1, 2, 3 or 4 days to frame the four levels of VSLs. The SDT has modified Attachment A to allow an implementation window of 3 days for implementation of the Frequency Bias Setting.</p> <p>With regard to R3, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.</p>		
<p>ACES Power Marketing Standards Collaborators/Great River Energy</p>	<p>No</p>	<p>The VSLs on for Requirement R1 set a previously un-established precedent of relying on the performance of other registered entities to establish the severity level of the violation. This is not appropriate. The VSLs should be rewritten to provide further gradations of the violation severity based on the BA's own performance.</p>
<p><b>Response:</b> The drafting team does not agree, but believes an explanation would be helpful.</p> <p>VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.</p> <p>Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.</p> <p>The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.</p>		

Organization	Yes or No	Question 5 Comment
Southern Company	No	<p>VSL for R2:We suggest the language in the VSL be consistent with the language used in the Requirement. The VSL for R2 says a BA ‘not receiving Overlap Regulation Service.....’ R2 says a BA ‘not participating in Overlap Regulation service shall .....’</p> <p>VSLs for R5:Since Frequency Bias Setting is expressed as a negative value, the terms “absolute value” and “less than” must be used carefully. This VSL uses “absolute value” when referring to the BA’s Frequency Bias Setting, but does not use “absolute value” when referring to the Frequency Response Obligation, or minimum value specified by the ERO. Consider revising this VSL so that a true comparison can be made.</p>
<p><b>Response: We agree with your suggested change for the VSL for R2 and corrected the mismatch between the requirement and the VSLs.</b></p> <p>[MEL21]</p>		
Tucson Electric Power	No	VSL's could be clearer and simpler. Allowance for the testing of other AGC modes should be considered.
<p><b>Response: The drafting team has made changes to VSLs based on specific suggestions. Regarding AGC operation, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.</b></p>		
Southwest Power Pool Regional Entity	Yes	Hard to follow the language for the VSL for R1. Suggest using formulas for ease of interpretation or provide an example in the Supporting Documentation.
<p><b>Response: The drafting team will provide an explanation in the Background Document.</b></p>		
Associated Electric Cooperative Inc	Yes	The VSLs appear reasonable for the risk and particularly where they assess higher severity when the BA or RSG Interconnection's performance was sub-standard as well.

Organization	Yes or No	Question 5 Comment
<b>Response: Thank you for your comment.</b>		
ISO/RTO Council Standards Review Committee	Yes	We do not have any issues with the VSLs, but wonder if the wording for R1 should have been "...Reserve Sharing Group's...". Alternatively, the wording after "interconnection's FRO" could be revised to: "...and the Balancing Authority's or the Reserve Sharing Group's FRM was..."
<b>Response: The drafting team agrees and <del>have</del> will make this change</b> [MEL22].		
Independent Electricity System Operator	Yes	We do not have any issues with the VSLs, but wonder if the wording for R1 should have been "...Reserve Sharing Group's...". Alternatively, the wording after "interconnection's FRO" could be revised to: "...and the Balancing Authority's or the Reserve Sharing Group's FRM was..."
<b>Response: The drafting team agrees and will make this change.</b>		
Texas Reliability Entity	Yes	We suggest that the Severe VSL for R3 is confusing and should be clarified as follows: "A Balancing Authority not receiving Overlap Regulation service failed to operate AGC in Tie Line Bias mode, when operation in Tie Line Bias mode would not have had an Adverse Reliability Impact on the Balancing Authority's Area."
<b>Response: Regarding AGC operation, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.</b>		
Imperial Irrigation District	Yes	
Salt River Project	Yes	
Energy Mark, Inc.	Yes	
FMPP	Yes	

Organization	Yes or No	Question 5 Comment
Xcel Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Keen Resources Asia Ltd.	Yes	

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6. The SDT divided the previously posted “Attachment A – Background Document” into two documents to provide additional clarity. The first document “Attachment A- Supporting Document” which details the methods used to develop the events to be analyzed, the FRO, FRM and Frequency Bias Setting. Do you agree that the revised Attachment A – Supporting Document provides sufficient clarity on the methodologies to be used? If not, please explain in the comment area.

**Summary Consideration:** The majority of the commenters pointed out that there was a discrepancy between Attachment A and the Background Document concerning the methodology used to calculate FRO. The SDT addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that Interconnection.

Several of the commenters indicated that the proposed standard did not provide a limit on the amount of Frequency Response that a BA was supposed to provide. The SDT added Paragraph #8 in Attachment A under the Event Selection Criteria to clarify that events greater than the limit in the criteria would be capped at a certain limit. This translates to a maximum expectation of Frequency Response equal to a Balancing Authority’s FRO times the number of .1 Hz shown in Table 2 in Attachment A.

Some commenters were confused about the intent of Attachment A. They indicated that Attachment A was describing both a methodology to select events and providing a background for the process (not a process/methodology). The intent of Attachment A is to describe the process that will be used. **There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date**<sup>[MEL23]</sup>. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it’s FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it cannot be changed without input from the industry.

As to the use of the term “may” in the attachment, at this time the drafting team is unable to further restrict the language due to the issues surrounding an individual event. As an example, frequency is scheduled at 60 Hz most of the time. However, when viewed on a graph or an EMS screen, it rarely sits at 60.000 for a long period of time, it fluctuates between 59.995 and 60.005. The drafting team is unable to say at this time that an event that starts with frequency at 60.005 is materially different than an event that starts at 59.995. Therefore, the drafting team has attempted to put guidance into the document as to what is pertinent without attempting to be overly restrictive in the selection criteria since there is no support for a restriction at this time. As more experience is gained, the process should be refined. If the refinement is significant enough to require a change to the Attachment A language, the process required to do so would be open to participation of industry and not done without public exposure.

A couple of commenters said that using older data for compliance could cause an entity to be in “double jeopardy”. The SDT discussed the concern of double jeopardy several times. At this time, the drafting team believes the issue of noise in individual events and the convergence of measurement of multiple events outweighs the double jeopardy concerns. The drafting team has, however, reduced the minimum number of events in a 12 month period to 20 from 25 but is still recommending that events from a previous year be used for the calculation if this number of events can not be found in that period.

A few o commenters indicated that the allocation of the FRO to the BAs was a “top down” approach. The SDT agrees with some of the comments made, but not in the conclusion drawn from the individual points. There is not currently an obligation to provide any amount of frequency response to a sudden change in interconnection frequency. The proposed standard addresses this shortcoming in the proposed standard.

The drafting team has also reduced the initial reduction in the minimum Frequency Bias Setting to ensure that the reduction can be studied closely to ensure no detrimental impact on the reliable operation of the Bulk Electric System.

Finally, there is ongoing disagreement in the industry as to whether it is desired to have a minimum Frequency Bias Setting that is significantly greater than the Frequency Response Characteristic.

A couple of commenters questioned whether point B was 18 seconds after the start of the disturbance set point B<sup>[MEL24]</sup>?. The SDT revised the language in the document to provide clarity on the 18 seconds. To the extent that the language is related to a specific definition of steady frequency, this has been worded intentionally to allow the process being developed by the ERO (specifically the Resources Subcommittee and the Frequency Working Group) to be adjusted based on experience that will only be gained through evaluation of actual events over the course of the next few years. Until that experience is gained, there will need to be some leeway in the process. The drafting team believes that the level of guidance provided in Attachment A is appropriate based on the information currently available.

Organization	Yes or No	Question 6 Comment
Western Area Power Administration, Western Area Power Administration - UGP Marketing	Negative	4. The allocation of FRO among BAs is a top-down approach instead of bottom up approach currently used. Currently, BAs calculate their FRC and set their Bias based on the greater of 1% peak load (1% generation for gen only BAs), or the average of frequency response characteristic of their BA over a year (FRC). These calculated individual biases get summed up and it becomes the Interconnection Bias value. The proposed standard has identified a set MW (for Western Interconnection 685 MW for

Organization	Yes or No	Question 6 Comment
		<p>0.1 of HZ) and is allocating it among all BAs. The individual BA’s allocated FRO is much lower than what BAs obligations’ presently are since the proposed standard lowers the bar for the BAs. The current approach is definitely superior to what is proposed since it more closely matches with the characteristic of the system and it protect the interconnection by requiring larger contribution than proposed standard.</p> <p>5. The allocation of FRO among the BAs in the interconnection favors the BAs with more load than more installed capacity</p>
<p><b>Response: 4. The drafting team agrees with some of the comments made here but not in the conclusion you draw from the individual points. There is not currently an obligation to provide any amount of frequency response to a sudden change in the interconnection frequency. The proposed standard addresses this shortcoming in the current standard. The drafting team has also reduced the initial reduction in the minimum Frequency Bias Setting to ensure that the reduction can be studied closely to ensure no detrimental impact on the reliable operation of the Bulk Electric System. Finally, there is ongoing disagreement in the industry as to whether it is desired to have a minimum Frequency Bias Setting that is significantly greater than the Frequency Response Characteristic. Please refer to Order 693 P371 for further information on this issue.</b></p> <p><b>5) After further discussion, the drafting team believes that the proposed allocation methodology does not favor any specific type of entity. To the extent that the commenter believes that the allocation favors any specific type of entity, the commenter should provide detailed reasoning of its position, not just an unsupported statement. The drafting team was unable to find any basis for this position during our discussions of the proposed allocation methodology. The drafting team will also point out that installed capacity is not a part of the calculation. The proposed allocation methodology, which has been clarified in the revised documents, utilizes monthly average peak generation and average peak load.</b></p>		
Seattle City Light	Negative	<p>Answer: No. Comments:</p> <p>o LADWP and SCL consider the increase in number of events to analyze (now 25) to be excessive. Previous years analyses typically involved 4-6 events; a permanent five-fold increase is not justified. SCL suggests reducing the baseline number of events from 25 to 12 per year. Analysis of a larger number of events could be requested on a year-by-year basis if conditions warrant, but should not be mandatory for all regions in all years.</p>

Organization	Yes or No	Question 6 Comment
<p>Response: The studies from the field trial show a convergence of the measurement after approximately 20 to 25 events. Based on the studies, the drafting team believes that a sample size as suggested would be very likely to cause entities to fail inappropriately due to the large amount of noise in the data related to each event. Additionally, there is a desire to ensure that the events picked are not weighted in such a way to cause the measurements to be increased over actual response. The drafting team has attempted to minimize the effort required of the reporting entities by developing the forms needed to calculate the FRM. Finally, the calculation process is being used for more than the previous process, not to mention that the previous process is not clearly defined and therefore not be used consistently across the industry.</p>		
<p>Alliant Energy Corp. Services, Inc.</p>	<p>Negative</p>	<p>Confusion exists around the "peak load" in that Attachment A states the allocation is based on Projected Peak Loads and Generation but the Background Document states it will use historical Peak and Generation to make the allocation. - There appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same approach. If installed capacity is used in the equation in Attachment A, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity of something less - please clarify. –</p> <p>It is not clear if there is an upper limit to the amount of frequency response expected of the BA's under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of FR expected on a total basis. BA's need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet the requirements.</p>
<p>Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection.</p> <p>The drafting team has added Paragraph #8 in Attachment A under the Event Selection Criteria to clarify events greater than that for which the requirement is planned will not be used to determine BA response [MEL25]. This translates to a maximum expectation of Frequency Response equal to a Balancing Authority's FRO times the number of .1 Hz shown in Table 2 in Attachment A.</p>		
<p>BrightSource Energy, Inc.; Clark Public Utilities; Tri-State</p>	<p>Negative</p>	<p>Confusion exists between Attachment A and the Background Document. Attachment A states peak load allocation is based on "Projected" Peak Loads and Generation, but</p>

Organization	Yes or No	Question 6 Comment
<p>G &amp; T Association, Inc.; Tucson Electric Power Co.; U.S. Army Corps of Engineers; South California Edison ; Platte River Power Authority; Pacific Gas and Electric Company; Colorado Springs Utilities; Idaho Power Company; California Energy Commission; California ISO; Deseret Power</p>		<p>the Background Document states it will use “historical” Peak Load and Generation.</p> <p>Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.</p> <p>The standard is unclear as to if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of Frequency Response expected on a total basis. Balancing Authorities need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet this requirement. The documents do not appear to provide any boundary on the maximum amount of Frequency Response that a BA will provide, i.e. it is not clear what will happen if an event occurs in the Eastern Interconnection that causes the frequency to drop to less than 59.6 Hz or in the Western Interconnection that causes the frequency to drop to less than 59.5 Hz, or if that event is excluded from the list used to calculate the Balancing Authorities’ response or is it included with an expectation that it counts the same as any other event. Without a clear statement of what is expected, including whether there is a limit on that expectation or not, it is unclear what is expected of the Balancing Authorities.</p> <p>Finally, why are there no requirements on governor installation, settings, and operation for a frequency response standard?</p>
<p><b>Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection.</b></p> <p><b>A reduction in the Frequency Bias Setting (FBS) may reduce the amount of AGC responses to a change in frequency. However, the drafting team has ensured that the FBS does not dip below the actual frequency response to ensure that the Frequency Response</b></p>		

Organization	Yes or No	Question 6 Comment
<p>is not withdrawn due to AGC action. With that said, there is currently not an obligation to provide any amount of frequency response to a sudden change in the interconnection’s frequency. The proposed standard addresses this shortcoming in the current standard. The drafting team has modified the initial reduction in the minimum Frequency Bias Setting to ensure that the reduction can be studied closely to ensure no detrimental impact on the reliable operation of the Bulk Electric System. Finally, there is ongoing disagreement in the industry as to whether it is desired to have a minimum Frequency Bias Setting that is significantly greater than the Frequency Response Characteristic. Please refer to Order 693 P371 for further information on this issue.</p> <p>The drafting team has added Paragraph #8 in Attachment A under the Event Selection Criteria to clarify events greater than that for which the requirement is planned <b>will not be used to determine BA response</b>. This translates to a maximum expectation of Frequency Response equal to a Balancing Authority’s FRO times the number of .1 Hz shown in Table 2 in Attachment A.</p> <p>The drafting team is operating under the Standard Authorization Requests (SARs) as approved. This drafting team believes that proposing a generator requirement is beyond the scope of the SARs. To the extent that the commenter believes there is a need to have a reliability standard related to generators, the drafting team would suggest that the commenter submit a SAR to begin the development process.</p>		
<p>Beaches Energy Services; City of Bartow, Florida; Tampa Electric Co.</p>	<p>Negative</p>	<p>On Event Selection Criteria, bullet 2, if 25 events cannot be identified then the ERO can go back in time to the previous year. This creates a double jeopardy to R1 of the standard. It also may include irrelevant data if there have been changes from one year to the next in FRO or Bias settings assigned by the ERO.</p> <p>On Frequency Response Obligation, first paragraph states that "Each Interconnection will establish target contingency protection criteria"; however, the Interconnection is not a decision-making body. Does this really mean the ERO will establish FRO for each Interconnection?</p> <p>The single asterisk note for the table on page 2 states: "It is extremely unlikely that an event elsewhere in the Eastern Interconnection would cause the Florida UFLS special protection scheme to “false trip”.", "Special protection scheme" should be stricken from this sentence, Florida has just a regional difference in its UFLS program.</p>
<p><b>Response:</b> The drafting team has discussed the concern of double jeopardy several times. At this time, the drafting team believes the issue of noise in individual events and the convergence of measurement of multiple events outweighs the double jeopardy</p>		

Organization	Yes or No	Question 6 Comment
<p>concerns. After further discussions, the drafting team has reduced the minimum number of events in a 12 month period to 20 from 25 but is still recommending that events from a previous year be used for the calculation if this number of events can not be found in that period.</p> <p>The drafting team modified the language to clarify that the ERO will set the IFRO<sub>[MEL26]</sub>.</p> <p>This modification was made.</p>		
<p>Salmon River Electric Cooperative</p>	<p>Negative</p>	<p>We feel that the drafting team has done an excellent job of providing clarify and reasonable reporting requirements to the right functional entity. We support the modifications but would like to have two additional minor modification in order to provide additional clarification to the Attachment I Event Table. We suggest the following clarifications: For the Event: BES Emergency resulting in automatic firm load shedding Modify the Entity with Reporting Responsibility to: Each DP or TOP that experiences the automatic load shedding within their respective distribution serving or Transmission Operating area. For the Event: Loss of Firm load for = 15 Minutes Modify the Entity with Reporting Responsibility to: Each BA, TOP, DP that experiences the loss of firm load within their respective balancing, Transmission operating, or distribution serving area. With these modifications or similar modifications we fully support the proposed Standard.</p>
<p><b>Response: The drafting team understands that this comment was submitted under the wrong project.</b></p>		
<p>FMPP</p>	<p>No</p>	<p>o Item 2 should be changed as follows: The ERO will identify at least 25 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify in a given evaluation period 25 frequency excursion events satisfying the limits specified in criteria 3 below, then similar acceptable events from the previous evaluation period also satisfying listed criteria will be included with the data set by the ERO for determining FRS compliance. (as written this item could cause double jeopardy for event from the previous period)</p> <p>o Under FRO for the Interconnection the first sentence should be changed as follows: "The ERO {Each Interconnection (delete these words)} will establish target</p>

Organization	Yes or No	Question 6 Comment
		<p>contingency protection criteria for each Interconnection.” (each Interconnection is not a governing entity)</p> <p>o The footnote under Table 2 of Attachment A should be changed as follows: The Eastern Interconnection set point listed is a compromise value for the highest UFLS step setting of 59.5Hz used in the east and the {special protection scheme’s (delete these words)} highest UFLS step setting of 59.7Hz used in Florida. It is extremely unlikely that an event elsewhere in the Eastern Interconnection would cause the Florida UFLS {special protection scheme (delete these words)} to “false trip”. (this is not a special protection system; it is just an UFLS)</p>
<p><b>Response:</b> The drafting team has discussed the concern of double jeopardy several times. At this time, the drafting team believes the issue of noise in individual events and the convergence of measurement of multiple events outweighs the double jeopardy concerns. After further discussions, the drafting team has reduced the minimum number of events in a 12 month period to 20 from 25 but is still recommending that events from a previous year be used for the calculation if this number of events can not be found in that period.</p> <p><b>The drafting team modified the language to clarify that the ERO will set the IFRO.</b></p> <p><b>This modification was made.</b></p>		
Seattle City Light	No	<p>o LADWP and SCL consider the increase in number of events to analyze (now 25) to be excessive. Previous years analyses typically involved 4-6 events; a permanent five-fold increase is not justified. SCL suggests reducing the baseline number of events from 25 to 12 per year. Analysis of a larger number of events could be requested on a year-by-year basis if conditions warrant, but should not be mandatory for all regions in all years.</p>
<p><b>Response:</b> The studies from the field trial show a convergence of the measurement after approximately 20 to 25 events. Based on the studies, the drafting team believes that a sample size as suggested would be very likely to cause entities to fail inappropriately due to the large amount of noise in the data related to each event. Additionally, there is a desire to ensure that the events picked are not weighted in such a way to cause the measurements to be increased over actual response. The drafting team has attempted to minimize the effort required of the reporting entities by developing the forms needed to calculate the FRM. Finally,</p>		



Organization	Yes or No	Question 6 Comment
<p>the calculation process is being used for more than the previous process, not to mention that the previous process is not clearly defined and therefore not used consistently across the industry.</p>		
Manitoba Hydro	No	<ol style="list-style-type: none"> <li>1. p.2 refers to each “Interconnection” establishing target contingency protection criteria. However, an “Interconnection” as defined in the NERC Glossary is an electrical system, not a Responsible Entity. This should be revised to clarify which Responsible Entities must establish the protection criteria.</li> <li>2. Table 2, although entitled “Interconnection Frequency Response Obligations” does not use the term FRO in the Table itself. This terminology should be consistent.</li> <li>3. There is no clear statement in Attachment A identifying the significance of Table 2. The previous paragraph identifies Table 2 as listing “default targets”, but how does this relate to the FRO referenced in R1?</li> <li>4. The “Note” on p.2 regarding the ERO being able to use additional events that don’t satisfy the criteria is unreasonable as drafted. Since these events are used to calculate the Frequency Bias Setting and FRM (as per p.1, s.2), the selection of events should not be at the unfettered discretion of the ERO. As drafted, no grounds or criteria must be satisfied.</li> </ol>
<p><b>Response:1. The drafting team modified the language to clarify that the ERO will set the IFRO.</b></p> <p>2. The drafting team modified the table to ensure consistent terminology is used.</p> <p>3. The drafting team modified Attachment A to clarify the importance and explain the calculations made to get to the Interconnection FRO.</p> <p>4. The drafting team revised the note to clarify that the ERO may use any event, regardless of size or other condition, in its evaluation of Interconnection Frequency Response. However, these additional events will not be used for evaluation of BA response compliance.</p>		
FPL	No	<p>3. - How many seconds of observation for “Delta F”? Does “Point C” in a. refer to “Figure 1 - Classic Frequency Excursion and Recovery” from NERC’s Survey</p>

Organization	Yes or No	Question 6 Comment
		<p>Instructions document dated September 1, 2010? If so it should be included in this document along with the added 8 and 18 second time lines being shown. What is a “narrow range” in item b.?</p> <p>4. - Better define “relatively steady” (i.e. within a specific range and state it?) Also, “near 60.000 Hz” is not precise enough (i.e. if the event begins below 60.000 Hz, what range or time error correction is to be considered acceptable?) Is the “A” value also part of the figure cited in 3?</p> <p>5. - Is the “B” value also part of the figure cited in 3?</p> <p>6. - Change “should be excluded” to “will be excluded”.</p> <p>7. - Better explain “the cleanest 2 or 3 frequency excursion events” or remove the word “cleanest”.</p> <p>Page 2 paragraph 5: Provide specific dates for the “quarterly postings” and where these will be posted (i.e. Internet address or other). Clarify the December 15 ERO annual post date with the dates stated for same posting on Page 3 paragraph 5 and the BA’s January 10 deadline. The BA posts 30 days from which date? This is confusing.</p> <p>Page 2 Table 2: What of starting event frequencies that are &lt; 60 Hz? Why is the “Highest UFLS” 59.6 when the Florida setting for its load is 59.7?</p> <p>Page 3 FRO equation: Page 4 of the “Frequency Response Standard Background Document, October 2011” also shows this equation but uses different terms. Make the same on both documents. In the Background Document each component of the numerator is explained and reference is made to FERC Form 714 to obtain these values. There is no reference to this form for the denominator values. All of this needs to be made clear with reference to FERC Form 714 on Attachment A.</p>
		<p><b>Response: 3. A retitle the columns in Table 1 of the Procedure document to clarify what was intended by the table. Point c defined above graph was added to help explain the points on a frequency graph used for the evaluation</b> [MEL27].</p>

Organization	Yes or No	Question 6 Comment
		<p><u>4 - Due to the complicated nature of event evaluation and selection, the drafting team has retained the words “relatively steady” and “near 60” in the document without providing further clarification or definition. The drafting team believes that the process being developed by NERC (specifically the NERC Resources Subcommittee and the Frequency Working Group) requires some leeway. As more experience is gained, the NERC Resources Subcommittee will attempt to document the process further.</u></p> <p><u>&amp;5 – No, the B value is a calculated value not shown in the chart referenced in number 3 above. Additional language has been added in Attachment A to clarify both the A value and the B value. The A and B values are shown on Figure 2 of the Background document as green and red lines, respectively. The drafting team has added additional explanatory text in the event selection section to provide better understanding.</u> [MEL28].</p> <p>6 – The drafting team modified this language.</p> <p>7 – Due to the complicated nature of event evaluation and selection, the drafting team has retained the word “cleanest” in the document without providing further clarification or definition. The drafting team believes that the process being developed by NERC (specifically the NERC Resources Subcommittee and the Frequency Working Group) requires some leeway. As more experience is gained, the NERC Resources Subcommittee will attempt to document the process further.</p> <p>NERC is developing this part of the process and an area to post this information. The drafting team has put clear language in the attachment requiring at least quarterly posting of events. It is currently the drafting team’s expectation that a list of potential events would be posted shortly after they actually occur and a refined list will be made available quarterly.</p> <p>Modifications to Table 2 have been made to clarify what is being used.</p> <p>Attachment A and the Background Document have been modified so that the FRO Allocation equation is the same and the terms are fully explained.</p>
Tucson Electric Power	No	<p>Attachment A creates additional requirements to the BAL-003-1 Standard. The arrested value of frequency observed within 8 seconds may not be long enough in some instances.</p> <p>The delta F in the West should be greater than 0.05 Hz to ensure a measurable frequency response.</p> <p>West Under Frequency should be set at 59.95 Hz. There is no reliability concern for Over Frequency.</p>

Organization	Yes or No	Question 6 Comment
		<p>Does 18 seconds after the start of the disturbance set point B?</p> <p>Pre-disturbance frequency should be relatively steady and near 60.000 Hz is vague. TEP feels that the ERO should not need to validate a BAs frequency bias setting.</p>
<p><b>Response:</b> The drafting team has modified the standard to put the requirements there and use Attachment A to clarify the process.</p> <p>After further discussion and review of the events in the Western Interconnection Form 1 for 2011, the drafting team has modified the Delta C and Under Frequency values in Table 1.</p> <p>Based on language in Order 693 P355, the drafting team believes that frequency response is needed in both directions, not just one.</p> <p>The drafting team has revised the language in the document to provide clarity on the 18 seconds. To the extent that the language related to a specific definition of steady frequency, this has been worded intentionally to allow the process being developed by the ERO (specifically the Resources Subcommittee and the Frequency Working Group) to be adjusted based on experience that will only be gained through evaluation of actual events over the course of the next few years. Until that experience is gained, there will need to be some leeway in the process. The drafting team believes that the level of guidance provided in Attachment A is appropriate based on the information currently available.</p> <p>Due to level of detail being used to determine the FBS and FRM as well as the interactions between this standard and others, the drafting team disagrees with the commenter and continues to recommend the ERO validate the FBS of each BA.</p>		
Bonneville Power Administration	No	<p>BPA believes that Attachment A adds additional requirements to the standard.</p> <p>Confusion exists between Attachment A and the Background Document. Attachment A states peak load allocation is based on “Projected” Peak Loads and Generation, but the Background Document states it will use “historical” Peak Load and Generation.</p> <p>3a: it may take longer than 8 seconds in some disturbances. This should be 10 seconds. .05 Hz Delta F is not low enough for the Western Interconnection, it should be .075Hz to ensure there is measurable frequency response for the interconnection. Also, under frequency should be set at 59.95 Hz. BPA does not believe there is a</p>

Organization	Yes or No	Question 6 Comment
		<p>reliability need to include over frequency events.</p> <p>3b: It is unclear if the 18 seconds is setting the B point. If this is the B point, BPA believes it should be changed to 25 seconds for the Western Interconnection.</p> <p>4. Please define relatively steady and near 60 Hz.</p> <p>6: For the Western Interconnection, BPA believes this needs to be 10 minutes at the top of the hour. As mid hour scheduling becomes more prevalent, the ramping at the bottom of the hour will have to be taken into account.</p> <p>FRO for the interconnection: Starting frequency should be the FTL limit. With RBC in place, the frequency is seldom at 60 Hz.</p> <p>BPA understands the theory behind setting the base obligation to the values listed in table 2. BPA would like to know if there were any studies performed to validate setting the FRO for the interconnection to such a low level?</p> <p>BA FRO and frequency bias setting: BPA does not agree with ERO assigning a Frequency Bias setting to each BA. This calculation is indicated as the initial FRO allocation, what is the process for changing it? BPA believes this should go through the standard drafting process for any changes. The calculation should use Peak online capacity, not the installed capacity. This would lead to the denominator being 2 X Peak projected load for the interconnection. BPA has approximately 35,000 MW of installed generation, and has never seen the actual coincidental generation go over 21,000 MW.</p> <p>Again, BPA doesn't believe the ERO should be validating the frequency bias setting. It is unclear to BPA how variable bias is being addressed in the standard.</p>
<p><b>Response: The drafting team has modified the requirements to address comments. The drafting team believes as modified the requirements are stated in the standard and the process to be used is in the Attachment.</b></p> <p><b>The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection.</b></p>		

Organization	Yes or No	Question 6 Comment
		<p>The drafting team has revised the language in the document to provide clarity on the 18 seconds. The drafting team has also attempted to clarify that the B Value is the average of the scan rate data for the period from 20 to 52 seconds following the start of the event. The event selection criteria will use the frequency approximately 18 seconds (prior to the start of the B Value period) to as frequency level to determine if the change in frequency qualifies as an event for the purposes of this standard. Based on event information for the 12 month period beginning December 2010, the drafting team has modified the frequency levels used for event qualification but did not modify the 18 second frequency point.</p> <p>To the extent that the language related to a specific definition of steady frequency, this has been worded intentionally to allow the process being developed by the ERO (specifically the Resources Subcommittee and the Frequency Working Group) to be adjusted based on experience that will only be gained through evaluation of actual events over the course of the next few years. Until that experience is gained, there will need to be some leeway in the process. The drafting team believes that the level of guidance provided in Attachment A is appropriate based on the information currently available.</p> <p>Both the NERC Resources Subcommittee (RS) and the NERC Transmission Issues Subcommittee (TIS) evaluated the level of response needed. The drafting team decided to use the limits determined by the RS over that determined by the TIS after evaluation of both. The documents developed by both of these subcommittees are available on the NERC <a href="#">website</a> <sup>[MEL29]</sup> <a href="#">under this project</a>.</p> <p>The drafting team clarifies that the ERO is not assigning the Frequency Bias Setting. The ERO will review the data to determine that the Frequency Response Measure is correctly determined by the BA and that the Frequency Bias Setting is therefore correct. The expected process is that a subcommittee under NERC will review the Form 1 and Form 2 for each entity to ensure that the BA correctly filled out the form. Assuming the BA has correctly filled out these forms, there is no ERO interaction with the number provided by the BA.</p> <p>The FRO calculation is being included in the Attachment A to ensure that the process to modify the calculation would need to be open to industry input. It is not appropriate to put it in a requirement since it would not make sense to make a requirement that the FRO be allocated in a certain manner. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.</p> <p>The drafting team revised the requirements to separate the variable bias requirement from the fixed bias setting requirement and provide clarity related to what is expected in a variable bias setting.</p>
Energy Mark, Inc.	No	Comment 6: "If the ERO cannot identify in a given evaluation period 25 frequency excursion events satisfying the limits specified in criteria 3 below, then similar

Organization	Yes or No	Question 6 Comment
		<p>acceptable events from the previous evaluation period also satisfying listed criteria will be included with the data set by the ERO for determining FRS compliance." I believe that the better alternative in this case would be to use the lesser number of events. This is partly based on the consideration that if there are fewer events, the risk to the interconnection for that year was less than expected, and as a result, evaluation of fewer events will not compromise interconnection reliability. If fewer than 25 events are available in any year, the selection criteria should be adjusted to select more events.</p> <p>Comment 7: There are a number of problems with the use of "median" Frequency Response of the measured events. These problems make a choice other than median preferable. The following comments list some of those problems.</p> <p>Comment 8: The current standard uses average Frequency Response of selected events. This makes the current standard incompatible with the use of median.</p> <p>Comment 9: If a BA reconfigures during a measurement year, that reconfiguration will create a bi-modal distribution of the Frequency Response events. Median is incapable of representing a bi-modal distribution. The use of median will result in a standard that is incapable of measuring compliance effectively for an BA that is reconfigured during a measurement year (Dec 1 thru Nov 30).</p> <p>Comment 10: Any attempt to purchase additional Frequency Response from another BA for a portion of a measurement year will also cause a bi-modal distribution making the purchase of Frequency Response only effective for entire measurement years.</p> <p>Comment 11: Median is a non-linear measurement method. Because it is a non-linear measurement method, there is no valid way to manage partial year measurements.</p> <p>Comment 12: I will offer an alternative to median to the SDT before the end of the development of responses to these comments.</p> <p>Comment 13: The Minimum Frequency Bias Setting and the Frequency Response</p>

Organization	Yes or No	Question 6 Comment
		<p>Obligation are both based on a method that assigns responsibility based on a Peak Load / Peak Generation share of the interconnection. However, the method used to set the Minimum Frequency Bias Setting is different than the method used to determine the Frequency Response Obligation. Using these two different methods could result in the Minimum Frequency Bias Setting being less than the FRO for a BA. The best way to correct this problem is to use that same allocation methodology for determining the FRO and the Minimum Frequency Bias Setting. This can be easily accomplished by modifying R5 to use the FRO allocation method to determine the Minimum Frequency Bias Setting. This calculation would divide the numerator from the FRO allocation equation, divide it by two and multiply it by the percentage specified in Attachment B. In fact, the current FRS Form 1 uses this equation with projected rather than historic data. The best alternative would be to modify the R5 in the standard to match the FRO allocation method and modify FRS Form 1 to use historic data instead of projected data. This would result in only one set of Peak Load and Peak Generation data throughout the standard, rather than three different sets of data as currently written. When multiple sets of the same or similar data are used within a single standard, it only creates confusion and errors in the result.</p>
<p><b>Response: Comment 6:</b> The studies from the field trial show a convergence of the measurement after approximately 20 to 25 events. Based on the studies, the drafting team believes that a sample size as suggested would be very likely to cause entities to fail inappropriately due to the large amount of noise in the data related to each event. Additionally, there is a desire to ensure that the events picked are not weighted in such a way to cause the measurements to be increased over actual response. The drafting team has attempted to minimize the effort required of the reporting entities by developing the forms needed to calculate the FRM. Finally, the calculation process is being used for more than the previous process, not to mention that the previous process is not clearly defined and therefore not used consistently across the industry.</p> <p><b>Comment 7-12:</b> The drafting team is recommending use of the median for the purposes of determining a BA FRM over multiple events. This decision is based on the determination that, while it may not be perfect, it is better than the other alternatives available at this time. The drafting team recognizes that in the future a better methodology might be found; based on the data available at this time the median allows us to move forward to implement a response requirement.</p> <p><b>Comment 13:</b> The drafting team understands your concern of using the historical numbers for the FRO allocation and the</p>		



Organization	Yes or No	Question 6 Comment
<p>projected number as the basis for the minimum Frequency Bias Setting. However, after discussions, the drafting team believes that at this time, minimizing the changes to the current Frequency Bias Setting process provides better comparability for the purpose of evaluating the impacts of reducing the minimum setting requirement. In the alternative, the drafting team feels that allocating the FRM based on historical data provides less room to game the process since the numbers used for allocation can be verified independently.</p>		
MRO NSRF	No	<p>Confusion exists around the “peak load” in that Attachment A states the allocation is based on Projected Peak Loads and Generation but the Background Document states it will use a historical Peak and Generation to make the allocation. Also, for the BA installed capacity, where is that value derived from and does NERC obtain that from FERC form data or does the BA provide that information somewhere specific to this effort? Additionally, there appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same approach. If installed capacity is used in the equation, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity? Please clarify. We suggest the SDT clarify if the materials in the revised Attachment A (and Attachment B) are “Guideline” or “Technical Background”, or “requirements</p>
<p><b>Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.</b></p>		
Xcel Energy	No	<p>Confusion exists around the “peak load” in that the Attachment A states the allocation is based on Projected Peak Loads and Generation but the Background Document states it will use a historical Peak and Generation to make the allocation. Also, for the BA installed capacity, where does that value come from and does NERC obtain that from FERC form data or does the BA provide that information somewhere specific to this effort? Additionally, there appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document.</p>

Organization	Yes or No	Question 6 Comment
		<p>These differences should be reconciled such that both documents address the same approach. If installed capacity is used in the equation, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity?</p>
<p><b>Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and monthly peak generation (monthly peak) and does not use installed capacity.</b></p>		
<p>ISO/RTO Council Standards Review Committee</p>	<p>No</p>	<p>Despite the SDT’s good faith effort to convert the previous Attachment A into two separate documents (Attachments A and B), the modified Attachment A is problematic. As many commenters indicated, the previous Attachment A, other than the section providing guidance on event selection, appears to be explanatory, contextual, and instructional in content. These aspects are important, but do not rise up to the level of requirements to drive reliability performance/outcome. Attachment A should include only the event selection process and calculations associated with the requirements, including an explanation of what is necessary if variable Frequency Bias Settings are implemented. If other "requirements" need to be specified, such as the reporting time frame stipulated on P. 3 of Attachment A, they should be moved to the standard itself but not imbedded in an attachment. We suggest that the SDT first determine if the materials in the revised Attachment A (and Attachment B) are “Guideline” or Technical Background”, or are they “requirements”. If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as-written Attachment A is a mix bag as it on the one hand describes the ERO’s process for supporting the Frequency Response Standard (FRS), in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM, and on the other hand the BA’s obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which is not held responsible for complying with the proposed method. Further, there are no measures provided for the requirements stipulated/imbedded in Attachment A so</p>

Organization	Yes or No	Question 6 Comment
		<p>how can the Responsible Entity (BA, in this case) be assessed for compliance? We suggest the SDT move those requirements on the BA to the main standard, and turn Attachment A into an appendix describing the calculation process. An appendix is not regarded as a mandatory requirement. Similar comments apply to Attachment B. Moreover, if the Attachments are to be integral to the standards, the terminology “may” must be replaced with “shall”.</p> <p>Finally, the two Attachments are listed in Section F - Associated Documents. This Section is generally used to list reference documents that are NOT standard requirements. We suggest the SDT review and revise this listing depending on its final determination of the status of the two Attachments (or their revisions, where appropriate<sup>[MEL30]</sup>).</p>
<p><b>Response:</b> The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it’s FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it can not be changed without input from the industry. As to the use of the term “may” in the attachment, at this time the drafting team is unable to further restrict the language due to the issues surrounding an individual event. As an example, frequency is scheduled at 60 Hz most of the time. However, when viewed on a graph or an EMS screen, it rarely sits at 60.000 for a long period of time, it fluctuates between 59.995 and 60.005. The drafting team is unable to say at this time that an event that starts with frequency at 60.005 is materially different that an event that starts at 59.995. Therefore, the drafting team has attempted to put guidance into the document as to what is pertinent without attempting to be overly restrictive in the selection criteria since there is no support for a restriction at this time. As more experience is gained, the process should be refined. If the refinement is significant enough to require a change to the Attachment A language, the process required to do so would be open to participation of industry and not done without public exposure.</p> <p><u>Done</u></p>		
Independent Electricity	No	Despite the SDT’s good faith effort to convert the previous Attachment A into two separate documents (Attachments A and B), the modified Attachment A is

Organization	Yes or No	Question 6 Comment
System Operator		<p>problematic. As many commenters indicated, the previous Attachment A, other than the section providing guidance on event selection, appears to be explanatory, contextual, and instructional in content. These aspects are important, but do not rise up to the level of requirements to drive reliability performance/outcome. Attachment A should include only the event selection process and calculations associated with the requirements, including an explanation of what is necessary if variable Frequency Bias Settings are implemented. If other "requirements" need to be specified, such as the reporting time frame stipulated on page 3 of Attachment A, they should be moved to the standard itself but not imbedded in an attachment. We suggest the SDT to first determine if the materials in the revised Attachment A (and Attachment B) are "Guideline" or "Technical Background", or are they "requirements". If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as-written Attachment A is a mix bag as it on the one hand describes the ERO's process for supporting the Frequency Response Standard (FRS) (in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM), and on the other hand the BA's obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which, by the way, is not held responsible for complying with the proposed method. Further, there are no measures developed for the requirements stipulated/imbedded in Attachment A so how can the Responsible Entity (BA, in this case) be assessed for compliance?</p> <p>We suggest the SDT to move those requirements on the BA to the main standard, and turn Attachment A into an appendix describing the calculation process. An appendix is not regarded as a mandatory requirement. Similar comments apply to Attachment B.</p> <p>Finally, the two Attachments are listed in Section F - Associated Documents. This Section is generally used to list reference documents that are NOT standard requirements. We suggest the SDT review and revise this listing depending on its final determination of the status of the two Attachments (or their revisions, where</p>

Organization	Yes or No	Question 6 Comment
		appropriate).
<p>Response: The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it's FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments and modified them to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it can not be changed without input from the industry. As to the use of the term "may" in the attachment, at this time the drafting team is unable to further restrict the language due to the issues surrounding an individual event. As an example, frequency is scheduled at 60 Hz most of the time. However, when viewed on a graph or an EMS screen, it rarely sits at 60.000 for a long period of time, it fluctuates between 59.995 and 60.005. The drafting team is unable to say at this time that an event that starts with frequency at 60.005 is materially different that an event that starts at 59.995. Therefore, the drafting team has attempted to put guidance into the document as to what is pertinent without attempting to be overly restrictive in the selection criteria since there is no support for a restriction at this time. As more experience is gained, the process should be refined. It the refinement is significant enough to require a change to the Attachment A language, the process required to do so would be open to participation of industry and not done without public exposure.</p>		
Florida Power & Light Company	No	<p>In the table on page2 the asterick references a statement that the 59.7Hz used in Florida is a special protection scheme. This is incorrect. The special protection scheme setting was 59.82Hz and was done away with in 2005 or earlier. The 59.7Hz setting used within the FRCC is based on FRCC TWG studies that require this level of setting to protect the state in the event of a separation and to protect nuclear equipment. FPL supports the use of the C(N-2) critiera. Additionally, the reference to the FERC714 report that is currently in the background data should be made part of attachment A not separated. FPL fully agrees with Table 1The formula used to derive the FRO is inconsistant with the definition used for requirement R5. R5 states that the load is " within the BA's metered boundary". The load used in the formulae is taken from FERC714. The yearly peak demand used in R5 should be the peak monthly load from June, July or August as reported on FERC714 to be compatible with the FRO formula.</p>

Organization	Yes or No	Question 6 Comment
<p>Response: The drafting team has removed the reference to the special protection scheme. The drafting team has modified the FRO allocation formula to better explain what is desired. However, the drafting team did not adjust the formula to what is suggested by the commenter.</p>		
NV Energy	No	<p>It is not clear whether the calculation of FRO is to utilize projections of BA load as in Att A, or past data reported in FERC Form 1 as per the Background Document.</p>
<p>Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.</p>		
Los Angeles Department of Water and Power	No	<p>LADWP considers the increase in number of events to analyze (now 25) to be excessive. Previous years analyses typically involved 4-6 events; a permanent five-fold increase is not justified. LADWP suggests reducing the baseline number of events from 25 to 12 per year. Analysis of a larger number of events could be requested on a year-by-year basis if conditions warrant, but should not be mandatory for all regions in all years.</p>
<p>Response: The studies from the field trial show a convergence of the measurement after approximately 20 to 25 events. Based on the studies, the drafting team believes that a sample size as suggested would be very likely to cause entities to fail inappropriately due to the large amount of noise in the data related to each event. Additionally, there is a desire to ensure that the events picked are not weighted in such a way to cause the measurements to be increased over actual response. The drafting team has attempted to minimize the effort required of the reporting entities by developing the forms needed to calculate the FRM. Finally, the calculation process is being used for more than the previous process, not to mention that the previous process is not clearly defined and therefore not used consistently across the industry.</p>		
JEA Electric Compliance/Florida Municipal Power Agency	No	<p>On Event Selection Criteria, bullet 2, if 25 events cannot be identified then the ERO can go back in time to the previous year. This creates a double jeopardy to R1 of the standard. It also may include irrelevant data if there have been changes from one</p>

Organization	Yes or No	Question 6 Comment
		<p>year to the next in FRO or Bias settings assigned by the ERO.</p> <p>On Frequency Response Obligation, first paragraph states that "Each Interconnection will establish target contingency protection criteria"; however, the Interconnection is not a decision-making body. Does this really mean the ERO will establish FRO for each Interconnection?</p> <p>The single asterisk note for the table on page 2 states: "It is extremely unlikely that an event elsewhere in the Eastern Interconnection would cause the Florida UFLS special protection scheme to "false trip".", "Special protection scheme" should be stricken from this sentence, Florida has just a regional difference in its UFLS program.</p>
<p><b>Response: The drafting team has discussed the concern of double jeopardy several times. At this time, the drafting team believes the issue of noise in individual events and the convergence of measurement of multiple events outweighs the double jeopardy concerns. After further discussions, the drafting team has reduced the minimum number of events in a 12 month period to 20 from 25 but is still recommending that events from a previous year be used for the calculation if this number of events can not be found in that period.</b></p> <p><b>The drafting team modified the language to clarify that the ERO will set the IFRO.</b></p> <p><b>This modification was made.</b></p>		
Duke Energy	No	<p>On page 3 of the document it states "For a multiple Balancing Authority Interconnection, the Interconnection Frequency Response Obligation is allocated based upon either the Balancing Authority Peak Demand or peak generation", however, the initial FRO allocation equation shows that the BA allocation is based upon the sum of the Projected BA Peak Load plus installed capacity, times the Interconnection FRO, and divided by the sum of the Projected Interconnection Peak Load plus Interconnection installed capacity. Is the statement in quotes correct, or is the allocation equation correct? In addition, the equation in Attachment A referencing "installed capacity" conflicts with the equation in the BAL-003-1 Background Document entitled "Frequency Response Standard Background Document" where "Peak Gen" is used. In summary, is the FRO allocation based upon</p>

Organization	Yes or No	Question 6 Comment
		<p>an equation which a) sums the Projected BA Peak Load plus peak generation, b) sums the Projected BA Peak Load plus installed capacity, or c) uses either Projected BA Peak Load OR peak generation? All three options are currently represented in the documentation.</p> <p>Calculation of the FRO for the Eastern Interconnection: Duke Energy agrees with the criteria suggested for the event to be protected (4500 MW), and at this time also agrees with the “compromise” low limit of 59.6 Hz. However, knowing that another Standard is under development which may require hourly assessment of available “frequency responsive reserves”, we are trying to determine what impact the choice of this methodology will have on the amount of frequency responsive reserves the industry will have to maintain - enough to cover frequency swings that only occasionally reach down to perhaps 59.9 Hz as we see on the Interconnection today (essentially the allocated FRO for a 0.1Hz deviation), enough to cover a 4500 MW loss, or whatever we deem appropriate as long as we are compliant to the FRM? We recognize that the Standard Drafting Team cannot answer this question, as the Standard under development is not within the scope of this team, however our comment is meant to illustrate the point that similar to our response to question 8, it should be recognized that elements of this Standard are tightly coupled to other current and potential Standards, and the impacts must be considered by the Industry.</p>
<p><b>Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.</b></p> <p><b>The drafting team has added Paragraph #8 in Attachment A under the Event Selection Criteria to clarify events greater than that for which the requirement is planned will not be used to determine BA response compliance. This translates to a maximum expectation of Frequency Response equal to a Balancing Authority’s FRO times the number of .1 Hz shown in Table 2 in Attachment A.</b></p>		



Organization	Yes or No	Question 6 Comment
SERC OC Standards Review Group	No	The definition of Single Event Frequency Response Data (SEFRD) was struck from the draft standard but still appears in Attachment A. Since R1 of the standard references Attachment A, would the definition of SEFRD still be applicable? If the definition is to be totally struck, we don't think the term should be used in Attachment A.
<p><b>Response: The SEFRD definition was moved to Attachment A. The SEFRD is used on individual events. The median of a BA's SEFRDs will be used to determine its FRM. Therefore, the drafting team believes it is appropriate to use the definition in the Attachment. Since it is not likely to be used outside of the context of this standard, the drafting team is not proposing to place the definition in the NERC Glossary.</b></p>		
Hydro-Quebec TransEnergie	No	The Event Selection Criteria should be modified for the Quebec Interconnection. In Table 1, the change in frequency (Delta f) used for Quebec's Event Selection Criteria should be 0,3Hz (from point "A" to point "C") and must last for at least 7 seconds so that we don't measure AGC action. In addition, a criterion should be added by saying that events that recovered within the 20-52 second average period for point "B" should be excluded from analysis.
<p><b>Response: The drafting team has modified Attachment A to address these comments.</b></p>		
Keen Resources Asia Ltd.	No	The sample pre-selection described in Attachment A, Event Selection, Criteria 2 & 7, violates the fundamental statistical procedure of unbiased sampling. A population is governed by a single "process" which, when stationary, is represented by a fixed probability distribution. In this case the population is several years of events (which are the subject of Frequency Response), not of normal operating control errors which are the subject of CPM control. A sample is governed by a single process that approximates the process governing the population as the sample gets larger, in this case if it includes several years of data. Samples are measured "as they come", no triage/filtering allowed, and they are called "stratified" when their distribution approximates the population distribution. Unlike normal operating errors, samples of events are not evenly distributed over a year. The attempt in criteria 2 & 7 to pre-select only certain events, and not others, in such a way that the selected events

Organization	Yes or No	Question 6 Comment
		<p>occur evenly throughout the year, is papently wrong because it is trying to "fit" events into a process (even distribution over time) that does not govern events, but that instead governs normal operating errors that are the subject of CPM control, not of this Frequency Response standard. In other words, criteria 2 &amp; 7 confuse Frequency Response with CPM, and events with normal operating errors. The result is a false, biased sample which destroys the integrity of this standard. Paragraph 4 on page 5 of the Background Document, on the other hand, provides a statistically correct description of event selection without sample pre-selection and should followed instead of the erroneous criteria 2 &amp; 7 in Attachment A.</p>
<p><b>Response: The drafting team has discussed this issue several times and believes that issues related to measurement caused by noise in individual events and the need to ensure adequate representation of events throughout the year outweigh the concern to have a “pure” statistical sample. For these reasons the drafting team has not modified the event selection criteria.</b></p>		
<p>Northeast Power Coordinating Council</p>	<p>No</p>	<p>The SDT has to first determine if the materials in the revised Attachment A &amp; B are “Guideline” or Technical Background”, or are they “requirements”. If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as written Attachment A is confusing as it describes the ERO’s process for supporting the Frequency Response Standard (FRS) (the method and criteria it uses to calculate the frequency bias settings and the FRM), and at the same time the BA’s obligations to support this process. The latter requirements should not be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which is not held responsible for complying with the proposed method. An appendix is not regarded as a mandatory requirement.</p> <p>Additionally, regarding BAL-003-1- Attachment A 1. Criterion 5 needs to be re-written for clarity.</p> <p>2. Criterion 7 refers to “cleanest events”. A statement of what constitutes a “clean event” is needed to avoid possible controversy in the future.</p>

Organization	Yes or No	Question 6 Comment
		<p>3. The use of 59.6 Hz as the highest UFLS setting is flawed. It should either be 59.7 Hz as a deliberate choice to protect Florida interests, or it should be 59.5 Hz without concern for Florida’s unique settings.</p> <p>4. In the last 2 sentences at the end of the section on Frequency Response Obligation, it refers to an Interconnection being able to offer “alternate FRO protection criteria”. The Interconnection should have been an integral part of establishing its obligation. It is stated that the “ERO will confirm” the “alternate FRO protection criteria”. Does this mean the ERO unconditionally approves it, or evaluates with a right of rejection? Please clarify.</p> <p>5. In the formula for determining the Balancing Authority’s FRO allocation, installed capacity is used. Does the industry have a clear and consistent definition for installed capacity? Also, with greater wind energy development, the delivered capacity over longer time horizons will be substantially less than nameplate machine ratings. The background document refers to the use of peak generation instead of installed capacity. Which shall be used? Please clarify.</p> <p>6. Recent studies have shown that the 18-52 second sampling interval does not work well for the Quebec Interconnection, in part due to the excellent and high level of response found in that Interconnection. The standard needs to be modified such that the sampling interval is that which works the best for each individual interconnection.</p> <p>7. Attachment A needs to define the point A sampling interval.</p>
<p><b>Response:</b> The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it’s FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it can not be changed without input from the industry.</p> <p><b>1. The drafting team believes that Criterion 5 is clear as written. The comment does not provide any guidance as to what needs</b></p>		

Organization	Yes or No	Question 6 Comment
<p>clarification so no change was made.</p> <p>2. Due to the complicated nature of event evaluation and selection, the drafting team has retained the word “cleanest” in the document without providing further clarification or definition. The drafting team believes that the process being developed by NERC (specifically the NERC Resources Subcommittee and the Frequency Working Group) requires some leeway. As more experience is gained, the NERC Resources Subcommittee will attempt to document the process further.</p> <p>3. The drafting team has revised the terminology used to explain the frequency levels proposed. There was not a change to the Eastern Interconnection numbers.</p> <p>4. An interconnection can recommend a change to the table. As the standards process currently works, that interconnection would need to support its alternative level with data. If the interconnection has a single Regional Reliability Organization, the ERO would typically agree to the alternative assuming it would be more restrictive (in this case a larger response requirement) than the ERO has recommended.</p> <p>5. The drafting team has addressed the concerns raised by clarifying that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.</p> <p>6. The drafting team has modified Attachment A to address concerns with selection of an event where frequency returns to the A Value level during the measurement period. These events will be excluded from the measurement process for all interconnections.</p> <p>7. The definition of the terms are provided in the background document as well as the formulas in the spreadsheets.</p>		
<p>Sacramento Municipal Utility District (SMUD)</p>	<p>No</p>	<p>The standard is unclear as to if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of Frequency Response expected on a total basis. Balancing Authorities need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet this requirement. The documents do not appear to provide any boundary on the maximum amount of Frequency Response that a BA will provide, i.e. it is not clear what will happen if an event occurs in the Eastern Interconnection that causes the</p>

Organization	Yes or No	Question 6 Comment
		<p>frequency to drop to less than 59.6 Hz or in the Western Interconnection that causes the frequency to drop to less than 59.5 Hz, or if that event is excluded from the list used to calculate the Balancing Authorities' response or is it included with an expectation that it counts the same as any other event. Without a clear statement of what is expected, including whether there is a limit on that expectation or not, it is unclear what is expected of the Balancing Authorities.</p>
<p><b>Response: The drafting team has added Paragraph #8 in Attachment A under the Event Selection Criteria to clarify events greater than that for which the requirement is planned will not be used to determine BA response. This translates to a maximum expectation of Frequency Response equal to a Balancing Authority's FRO times the number of .1 Hz shown in Table 2 in Attachment A.</b></p>		
<p>Western Electricity Coordinating Council</p>	<p>No</p>	<p>There is disagreement between Attachment A and the Background Document. Attachment A states peak load allocation is based on "Projected" Peak Loads and Generation, but the Background Document states it will use "historical" Peak Load and Generation.</p> <p>The allocation methodology of FRO among the BAs in the equation on page 3 of Attachment A favors BAs with more load than more installed capacity. Peak load is served but not all installed capacity is always dispatched.</p>
<p><b>Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.</b></p>		
<p>Alberta Electric System Operator</p>	<p>No</p>	<p>These documents not only provide additional clarity but also specify additional requirements, such as FRS Form 1 annual reporting by January 10. All the enforceable requirements should be included in the body of the standard.</p> <p>1. Attachment A uses the terms "delta F (change in frequency)", "arresting frequency (Point C)", "B Value", "A Value". These terms are not properly defined or described in</p>

Organization	Yes or No	Question 6 Comment
		<p>this document as drafted. The AESO suggests adding a description or definitions for clarity in this document.</p> <p>2. The standard gives 2 sets of values for Interconnection Frequency Response Obligation in Table 2, (1) Base Obligation and (2) the obligation including 25% Safety Margin (which seems to be implied by the "contingency protection criterion"). The Attachment A does not specify whether the Base Obligation or the 25% Safety Margin value will be used to allocate the Interconnection FRO to the BAs. Please clarify which value will be used to calculate the BA Frequency Response Obligation (FRO) in the Interconnection FRO allocation formula in Attachment A.</p> <p>3. The "initial FRO allocation" formula in Attachment A uses Peak Load. The term Peak Load is not used in the standard nor is it a defined term in the NERC Glossary. The standard uses Peak Demand, which is defined in the Glossary Is "Peak Load" synonymous with "Peak Demand"? If so, Peak Demand should be used in the formula instead. Otherwise Peak Load should be clearly defined in this document.</p> <p>4. Is "Projected" in the FRO allocation formula synonymous with "Forecasted"? If so, Forecasted should be used for consistency. Otherwise "Projected" or the context in which it appears must be defined.</p>
<p><b>Response: The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it's FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it can not be changed without input from the industry.</b></p> <p><b>1. The definition of the terms are provided in the background document as well as the formulas in the spreadsheets.</b></p> <p><b>2. The drafting team has modified Table 2 to clarify that the bottom number in each column is the Interconnection FRO. The Interconnection FRO will be allocated to the BAs within that interconnection.</b></p> <p><b>3 and 4. The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for</b></p>		

Organization	Yes or No	Question 6 Comment
<p><b>the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.</b></p>		
<p>Great River Energy/ACES Power Marketing Standards Collaborators</p>	<p>No</p>	<p>Under item 3 of the Event Selection Criteria section, the delta F and Point C should be described either in this attachment or the “Frequency Response Standard Background Document”. While many in industry may understand what these terms mean, history has a way of getting lost with personnel turnover. Furthermore, this would help ensure that the auditors and industry have a duplicate understanding.</p> <p>In the Frequency Response Obligation section on page 2, several items require more description. Further description of why an N-2 event was chosen for the Contingency Protection Criteria should be provided and which N-2 event was selected so that industry can help validate if the correct MW value was selected.</p> <p>Furthermore, the document should clarify if the Contingency Protection Criteria contains the “safety margin”. There is a statement in the paragraph before the table that states it does but then the table lists out a separate 25% “Safety Margin”. Thus, it is not clear if the “Safety Margin” is included in the Contingency Protection Criteria value listed in the table or not. “Safety margin” should be changed to “reliability margin”. Safety has a specific meaning in the electric industry and its use here is not appropriate. The Base Obligation should be explained. The explanation should include its purpose and origin.</p>
<p><b>Response: 1. The definition of the terms are provided in the background document as well as the formulas in the spreadsheets. The drafting team has clarified Table 2 by modifying the titles for each line.</b></p>		
<p>Texas Reliability Entity</p>	<p>No</p>	<p>We have a number of concerns regarding Attachment A which are set forth below:</p> <ol style="list-style-type: none"> <li>1. Regarding the formula for “Initial FRO Allocation” on page 3 of Attachment A, the terms for “BA installed capacity” and “Interconnection installed capacity” are undefined and could be subject to manipulation and dispute. We suggest that this formula be revised to mirror the calculation based on well-established FERC Form 714</li> </ol>

Organization	Yes or No	Question 6 Comment
		<p>data that is discussed in the Background document, which is based on actual generation output.</p> <p>2. In Attachment A, all references to “Texas” should be changed to “ERCOT” as a reference to the Interconnection or the Region (including tables).</p> <p>3. Regarding the Event Selection Criteria in Attachment A: in item 2, consider whether certain events, such as DCS events, should be required to be included in the FRM analysis.</p> <p>4. Regarding the Event Selection Criteria in Attachment A: item 7 provides that the selected frequency excursion events are to be selected so that they are evenly distributed seasonally. Consider adding the seasonal distribution concept to item 2, particularly if it becomes necessary to include events from the previous evaluation period<sup>[MEL31]</sup>.</p> <p>5. In Attachment A, page 1 says the ERO is to post the final list of frequency excursion events by December 15, but on page 3 it suggests that the list will be posted by December 10. These references should be made consistent.</p> <p>6. Attachment A states, on page 3, “the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year: Frequency Bias Setting and Frequency Response Obligation (FRO).” What is meant by “the upcoming year”? Is the BA supposed to implement the new FBS immediately, or wait until the beginning of the next evaluation period on December 1? Note that if the new FRO and FBS are implemented immediately (e.g. in March), then the FRO will change in the middle of an evaluation period. This will complicate the comparison of FRM and FRO as required by R1.</p>
<p><b>Response:</b> 1. The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.</p>		



Organization	Yes or No	Question 6 Comment
<p>2. This change was made.</p> <p>3. The drafting team recommends all events with a frequency deviation that meets the selection criteria should be evaluated. For the entity that lost generation (or load) to initiate the event, the calculation methodology proposed allows adjustments to be made for that event.</p> <p>4. This modification was made. Procedure</p> <p>5. These two documents have been conformed.</p> <p>6. The ERO will notify the BAs as to the date the Frequency Bias Setting is to be implemented if they are utilizing a fixed Frequency Bias Setting.</p>		
Southern Company	No	<p>We suggest increasing the delta f for the East to be the same value as the West or larger. The reason for this is that the 0.04Hz suggested is too close to the governor deadbands of .036Hz. This would potentially omit frequency response that some units may provide for a larger excursion but not for those close to the deadband.</p>
<p>Response: The delta f values have been selected to balance the need to have a sufficient number of events for evaluation and the need to have sufficient frequency movement to actually measure response. At this time the drafting team is not modifying the eastern interconnection values based on the event selection process for the period December 2010 through November 2011.</p>		
ISO New England Inc	No	<p>We suggest the SDT to first determine if the materials in the revised Attachment A &amp; B are “Guideline” or Technical Background”, or are they “requirements”. If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as-written Attachment A is a mix bag as it on the one hand describes the ERO’s process for supporting the Frequency Response Standard (FRS), in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM, and on the other hand the BA’s obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which, by the way, is not held responsible for complying with the proposed method. An appendix is not regarded as a mandatory requirement.</p>

Organization	Yes or No	Question 6 Comment
		<p>Additionally, BAL-003-1- Attachment A</p> <ol style="list-style-type: none"> <li>1. Criterion 5 needs to be re-written for clarity.</li> <li>2. Criterion 7 refers to the “cleanest events”. Perhaps a statement of what constitutes a “clean event” is needed to avoid possible controversy in the future.</li> <li>3. The use of 59.6 Hz as the highest UFLS setting seems flawed. It should either be 59.7 Hz as a deliberate choice to protect Florida interests, or, it should be 59.5 Hz without concern for Florida’s unique settings.</li> <li>4. In the last 2 sentences at the end of the section on Frequency Response Obligation, it refers to an Interconnection being able to offer “alternate FRO protection criteria”. It seems that the Interconnection should have been an integral part of establishing its obligation. Also, it states that the “ERO will confirm” the “alternate FRO protection criteria”. Does this mean the ERO unconditionally approves it, or evaluates with a right of rejection? Please clarify.</li> <li>5. In the formula for determining the Balancing Authority’s FRO allocation, installed capacity is used. Does the industry have a clear and consistent definition for installed capacity? Also, with greater wind energy development, the delivered capacity over longer time horizons will be substantially less than nameplate machine ratings. Also, the background document refers to the use of peak generation instead of installed capacity. Which shall be used? Please clarify.</li> <li>6. Very recent studies have shown that the 18-52 second sampling interval does not work well for the Quebec Interconnection, in part due to the excellent and high level of response found in that Interconnection. The standard needs to be modified such that the sampling interval is that which works the best for each individual interconnection.</li> <li>7. Attachment A needs to define the point A sampling interval.</li> </ol>
<p><b>Response: The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that</b></p>		

Organization	Yes or No	Question 6 Comment
		<p>provides at least the response required of a BA based on it’s FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it can not be changed without input from the industry.</p> <ol style="list-style-type: none"> <li>1. The drafting team believes that Criterion 5 is clear as written. The comment does not provide any guidance as to what needs clarification so no change was made.</li> <li>2. Due to the complicated nature of event evaluation and selection, the drafting team has retained the word cleanest in the document without providing further clarification or definition. The drafting team believes that the process being developed by NERC (specifically the NERC Resources Subcommittee and the Frequency Working Group) requires some leeway. As more experience is gained, the NERC Resources Subcommittee will attempt to document the process further.</li> <li>3. The drafting team has revised the terminology used to explain the frequency levels proposed. There was not a change to the Eastern Interconnection numbers.</li> <li>4. An interconnection can recommend a change to the table. As the standards process currently works, that interconnection would need to support its alternative level with data. If the interconnection has a single Regional Reliability Organization, the ERO would typically agree to the alternative assuming it would be more restrictive (in this case a larger response requirement) than the ERO has recommended.</li> <li>5. The drafting team has addressed the concerns raised by clarifying that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.</li> <li>6. The drafting team has modified Attachment A to address concerns with selection of an event where frequency returns to the A Value level during the measurement period. These events will be excluded from the measurement process for all interconnections.</li> <li>7. The definition of the terms are provided in the background document as well as the formulas in the spreadsheets.</li> </ol>
Constellation Energy Commodities Group	Yes	Additional information relating to defining the FRO for the Interconnection would be helpful as would an example for calculating the BA FRO.

Organization	Yes or No	Question 6 Comment
<p><b>Response: The drafting team has revised Attachment A to provide better explanation and to clarify the allocation methodology to the BA.</b></p>		
American Electric Power	Yes	A frequency response observation should not be used spanning multiple years, or if there does, there should at least be a reset period.
<p><b>Response: The drafting team has discussed the concern of double jeopardy several times. At this time, the drafting team believes the issue of noise in individual events and the convergence of measurement of multiple events outweighs the double jeopardy concerns. After further discussions, the drafting team has reduced the minimum number of events in a 12 month period to 20 from 25 but is still recommending that events from a previous year be used for the calculation if this number of events can not be found in that period.</b></p>		
Cleco Corporation/ SPP Standards Review Group	Yes	We appreciate the effort of the SDT in developing Attachment A. It was very helpful in weeding through BAL-003.
<p><b>Response: Thank you for your comments.</b></p>		
Imperial Irrigation District	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Progress Energy	Yes	
Associated Electric Cooperative Inc	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 6 Comment
Ameren	Yes	

**7. The second document “BAL-003-1 Background Document” provides information behind the development of the standard. Do you agree that this new document provides sufficient clarity as to the development of the standard? If not, please explain in the comment area.**

**Summary Consideration:** The majority of the commenters referenced other questions in the comments. The SDT asked them to review the response to those earlier questions.

Several of the commenters pointed out that there was a discrepancy between the Background Document and Attachment A regarding the calculation of the BA FRO. The SDT has corrected the reference so both documents agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.

Some commenters indicated that Supplemental Regulation Service is not an appropriate method to provide Frequency Response. It is inappropriate to expect supplementary regulation to transfer frequency response successfully, however the SDT does not want to prevent any innovative solution that will transfer frequency response through the use of a pseudo-tie among Balancing Authorities. Also, the SDT believes that Balancing Authorities exchanging supplementary regulation via a pseudo-tie have to be consistent in the removal or inclusion of it in their actual net interchange measurement as well as in all events across the measurement period[MEL32].

Organization	Yes or No	Question 7 Comment
Seattle City Light	Negative	Answer: Yes Comments: o LADWP and SCL note that the document “BAL-003-1 Background Document” seems to be reasonable.

Organization	Yes or No	Question 7 Comment
<b>Response: Thank you for your comment.</b>		
Energy Mark, Inc.	No	Comment 14: Some of the information in this document concerning the Frequency Bias Setting for BAs participating in Overlap Regulation should be moved to the Supporting Document. This change would help in addressing Comments 3 & 4 under Question 2.
<b>Response: The SDT has added language to Attachment B to address your concern.</b>		
Duke Energy	No	Please see our comments to Question 6. In addition, Duke Energy disagrees with the statement on page 9 that Attachment B will “ensure there is no negative impact on other Standards” - please see our response to Question 8 for additional information.
<b>Response: Thank you for your comments. Please see the responses to Questions #6 and #8.</b>		
SERC OC Standards Review Group	No	Portions of the Background Document do not appear to be complete or finished. The Background Document should be edited to be consistent with changes made to the standard or other related documents (eg. elimination of the definition of SEFRD and any revisions to the draft BAL-003-1).
<b>Response: The SDT has made significant modifications to the Background Document to support the proposed standard. The SDT is proposing that this document be appended to the NERC Operating Manual (similar to other standards<sup>[MEL33]</sup>) <u>once the standard is approved.</u></b>		
ERCOT	No	Refer to comments in #1.
<b>Response: Refer to the response in Question #1.</b>		
Northeast Power Coordinating Council	No	Refer to the first comment in Question 6. For the Frequency Response Standard Background Document –

Organization	Yes or No	Question 7 Comment
		<p>1. Cite Attachment B in addition to Attachment A in the discussion of requirement R1.</p> <p>2. The Balancing Authority allocation method specified in this document does not agree with that in Attachment A.</p> <p>3. Drop the speculation on page 4 that most Balancing Authorities will be compliant. While it may be a commonly held belief by many that there is adequate frequency response right now, that assessment should be made after a targeted level of reliability has been defined and approved. The same comment applies on page 12.</p> <p>4. On page 6, drop the inappropriate recommendation of getting frequency response through supplemental regulation. It is inappropriate to try to substitute a “minute plus” product that is deployed centrally by the Balancing Authority for a “sub-minute” product that is deployed automatically without any Balancing Authority action. When a pseudo-tie is used, changes in the ACE values due to supplemental regulation are unrelated to and not coordinated with the need to deploy frequency response. Not only should this approach not be offered as an alternative, but the FRSDT should actively conduct research to determine if supplemental regulation via a pseudo-tie should be deliberately REMOVED from any actual net interchange calculation that may include it. This comment also applies to the mentioning of supplemental regulation on page 11 as well.</p> <p>5. On page 7, the reference to a 24 hour window on each side of the frequency bias setting implementation date is inconsistent with the wording of the standard. The standard states that any time within the designated date is acceptable.</p> <p>6. On page 8, the inclusion of “for training purposes” as a reason to not operate in tie line bias control should be dropped. This training can be done in a training simulator. If it is determined that it should be supported, then the requirement needs to be reworded to allow it explicitly.</p> <p>7. On page 14, the sentence: “This approach would only provide feedback for performance during that specific event and would not provide insight into the depth of response or other limitations” is difficult to understand. The paragraph would</p>

Organization	Yes or No	Question 7 Comment
		read better by simply deleting the sentence.
<p><b>Response: Please refer to our response to Question #6.</b></p> <p><b>Comment 1 – The SDT has modified the Background Document to incorporate your suggested change.</b></p> <p><b>Comment 2 – The SDT has corrected the reference so both documents agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</b></p> <p><b>Comment 3 – The SDT has removed the speculative language and replaced it with more appropriate language.</b></p> <p><b>Comment 4 - While the SDT agrees that it is inappropriate to expect supplementary regulation to transfer frequency response successfully, we do not want to prevent any innovative solution that will transfer frequency response through the use of a pseudo-tie among Balancing Authorities. Also, the SDT believes that Balancing Authorities exchanging supplementary regulation via a pseudo-tie have to be consistent in the removal or inclusion of it in their actual net interchange measurement as well as all events across the measurement period.</b></p> <p><b>Comment 5 – The SDT has corrected the background document to accurately reflect the language proposed in the standard.</b></p> <p><b>Comment 6 – The SDT has modified the background document to remove the training language.</b></p> <p><b>Comment 7 – The SDT has revised the paragraph to provide additional clarity.</b></p>		
Xcel Energy	No	Same comment here as the one in question 6.
<p><b>Response: Please refer to our response to Question #6.</b></p>		
ISO New England Inc	No	<p>See first comment in 6 above. Also, Frequency Response Standard Background Document –</p> <ol style="list-style-type: none"> <li>1. Cite Attachment B in addition to Attachment A in the discussion of requirement 1.</li> <li>2. The Balancing Authority allocation method specified in this document does not agree with that in Attachment A.</li> <li>3. Drop the speculation on page 4 that most Balancing Authorities will be compliant. While it may be a commonly held belief by many that there is adequate frequency</li> </ol>



Organization	Yes or No	Question 7 Comment
		<p>response right now, that assessment should be made after a targeted level of reliability has been defined and approved. The same comment applies on page 12.</p> <p>4. On page 6, drop the inappropriate recommendation of getting frequency response through supplemental regulation. It is inappropriate to try to substitute a “minute plus” product that is deployed centrally by the Balancing Authority for a “sub-minute” product that is deployed automatically without any Balancing Authority action. When a pseudo-tie is used, changes in the ACE values due to supplemental regulation are unrelated to and not coordinated with the need to deploy frequency response. Not only should this approach not be offered as an alternative, but the FRSDT should actively conduct research to determine if supplemental regulation via a pseudo-tie should be deliberately REMOVED from any actual net interchange calculation that may include it! This comment also applies to the mentioning of supplemental regulation on page 11 as well.</p> <p>5. On page 7, the reference to a 24 hour window on each side of the frequency bias setting implementation date is inconsistent with the wording of the requirement. The requirement says that any time within the designated date is acceptable.</p> <p>6. On page 8, the inclusion of “for training purposes” as a reason to not operate in tie line bias control should be dropped. This sort of training can be done in a training simulator. Alternatively, if it is determined that it should be supported, then the requirement needs to be reworded to allow it explicitly.</p> <p>7. On page 14, the sentence: “This approach would only provide feedback for performance during that specific event and would not provide insight into the depth of response or other limitations” is difficult to understand. The paragraph would read better by simply dropping it.</p>
<p><b>Response: Please refer to our response to Question #6.</b></p> <p><b>Comment 1 – The SDT has modified the Background Document to incorporate your suggested change.</b></p> <p><b>Comment 2 – The SDT has corrected the reference so both documents agree. The drafting team is proposing to use historical</b></p>		

Organization	Yes or No	Question 7 Comment
<p>information rather than forecasted information for the allocation of the Frequency Response Obligation.</p> <p>Comment 3 – The SDT has removed the speculative language and replaced it with more appropriate language.</p> <p>Comment 4 - While the SDT agrees that it is inappropriate to expect supplementary regulation to transfer frequency response successfully, we do not want to prevent any innovative solution that will transfer frequency response through the use of a pseudo-tie among Balancing Authorities. Also, the SDT believes that Balancing Authorities exchanging supplementary regulation via a pseudo-tie have to be consistent in the removal or inclusion of it in their actual net interchange measurement as well as all events across the measurement period.</p> <p>Comment 5 – The SDT has corrected the background document to accurately reflect the language proposed in the standard.</p> <p>Comment 6 – The SDT has modified the background document to remove the training language.</p> <p>Comment 7 – The SDT has revised the paragraph to provide additional clarity.</p>		
Western Electricity Coordinating Council	No	See response to question 6.
<p><b>Response: Please refer to our response to Question #6.</b></p>		
Alberta Electric System Operator	No	The Background Document uses BA Peak Generation in the BA FRO allocation formula. Attachment A uses BA Installed Capacity. The AESO suggests making the two formulae consistent.
<p><b>Response: The drafting team has corrected the reference so both documents agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</b></p>		
Florida Municipal Power Agency	No	The document does not discuss how the new reliability parameter will affect BAs
<p><b>Response: The new standard will require that Balancing Authorities meet a level of response to frequency events equal to or more negative than their Frequency Response Obligation. The SDT has made significant modifications to the Background Document which should address your concern.</b></p>		

Organization	Yes or No	Question 7 Comment
JEA Electric Compliance	No	The document does not discuss how the new reliability parameter will affect BAs
<p><b>Response: The new standard will require that Balancing Authorities meet a level of response to frequency events equal to or more negative than their Frequency Response Obligation. The SDT has made significant modifications to the Background Document which should address your concern.</b></p>		
MRO NSRF	No	<p>the MRO NSRF has restated the same answer as in question 6 on purpose. Confusion exists around the “peak load” in that Attachment A states the allocation is based on Projected Peak Loads and Generation but the Background Document states it will use a historical Peak and Generation to make the allocation. Also, for the BA installed capacity, where is that value derived from and does NERC obtain that from FERC form data or does the BA provide that information somewhere specific to this effort? Additionally, there appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same approach. If installed capacity is used in the equation, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity? Please clarify.</p> <p>Page 7 (3rd paragraph) of the Background document states “Given the fact that BA’s can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date.</p> <p>1) The Standard itself does not state this provision (24 hour window on each side of target date) as indicated.</p> <p>2) The SDT accurately addresses the fact that BA’s could have EMS or staffing issues during implementation of the ERO validated FBS. The current stated 72-hour window is not long enough for implementation of the FBS as there may be a host of issues that could impact implementation. We suggest that a seven day window be used for implementation of the FBS.</p>

Organization	Yes or No	Question 7 Comment
<p><b>Response: The drafting team has corrected the proposed standard to accurately reflect the language in the Background Document.</b></p>		
Texas Reliability Entity	No	<p>There is an inconsistency between the Background Document and Attachment A. Attachment A only proposes event criteria based on “the largest category C (N-2) event identified,” but the Background Document says: “Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection’s Frequency Response Obligation: - Largest category C loss-of-resource (N-2) event; - Largest total generating plant with common voltage switchyard; - Largest loss of generation in the interconnection in the last 10 years.”</p>
<p><b>Response: The drafting team has corrected the reference so both documents agree.</b></p>		
Great River Energy/ACES Power Marketing Standards Collaborators	No	<p>We can find no document titled “BAL-003-1 Background Document”. We assume this question is referring to the “Frequency Response Standard Background Document” dated October 2011. We do not believe the document provides sufficient clarity. No explanation is provided for why RSG was added to Requirement R1. There are typos contained in the document. On page 6 in NIA, the A should be in subscript. On page 7 in bullet 4 in the first sentence, “The” should be in lowercase</p>
<p><b>Response: Your assumption was correct. The drafting team has corrected these typos.</b></p>		
Southern Company	No	<p>We suggest the Background Document should be edited to be consistent with changes made to the standard or other related documents (eg. Any revisions to draft BAL-003-1 and removal of the definition of SEFRD).</p>
<p><b>Response: Thank you for your comments. The drafting team revised the background document based upon modifications to the standard as well as modifications to other documents related to the standard.</b></p>		
Seattle City Light	Yes	<p>o LADWP and SCL note that the document “BAL-003-1 Background Document” seems to be reasonable.</p>

Organization	Yes or No	Question 7 Comment
<b>Response: Thank you for your comments.</b>		
Constellation Energy Commodities Group	Yes	Should be revisited based on the proposed modifications to the requirements.
<b>Response: Thank you for your comments. The drafting team revised the background document based upon modifications to the standard as well as modifications to other documents related to the standard.</b>		
Los Angeles Department of Water and Power	Yes	LADWP notes that the document “BAL-003-1 Background Document” seems to be reasonable.
<b>Response: Thank you for your comments.</b>		
Keen Resources Asia Ltd.	Yes	Paragraph 4 on page 5 of the Background Document provides a statistically correct description of event selection without sample pre-selection and should followed instead of the erroneous criteria 2 & 7 in Attachment A. The risk-based approach to determining FRM, that the Background Document mentions in paragraph 4 of page 4 is being evaluated by the drafting team for application in this standard, should be considered for deployment as soon as possible to replace the administered method currently proposed in this standard, because the administered method lacks any technical justification. No such justification was ever attempted in the development of this standard. The administrative method of determining FRM is therefore but a highly dubious "quick fix" until the risk-based method is evaluated and implemented. The administrative method is in fact perverse because it discourages BAs from reducing their contribution to frequency error by refusing to reduce the BA's FRO accordingly, and because it encourages BAs to contribute to frequency error without increasing their FRO.
<b>Response: The standard has to be written with what will be used day one. Due to the timeline that NERC has filed with FERC, there is not enough time to adequately evaluate a second methodology.</b>		

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Yes	<p>Please see MH’s response to Question 1 regarding the term Single Event Frequency Response Data.</p> <p>Additionally, the discussion in this document is useful in clarifying the intent of the drafting team, but some of this clarification would best be incorporated into the Standard itself. Ex. RSG requirement on page 6. Also on page 7 Attachment A does not specify what validation is and how it is done. Attachment A refers to BA providing FBS data to ERO which then validates and publishes. This should be reflected in R2.</p>
<p><b>Response: Please refer to our response to Question 1.</b></p> <p><b>The “validation” process is nothing new. The ERO presently validates the information sent in by BAs today. The ERO will not be performing this process in a vacuum, but will be working with the BAs in the same manner as they presently do.</b></p>		
NV Energy	Yes	<p>This is a good reference; however see response to Question 6 in that there appears to be a discrepancy between Att A and the Background Document with regard to FRO calculation.</p>
<p><b>Response: The drafting team has corrected the discrepancy so both documents now agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</b></p>		
Cleco Corporation/SPP Standards Review Group	Yes	<p>We appreciate the effort of the SDT in developing the Background Document. It provided insight on how the SDT got the proposed standard to where it is with this posting.</p>
<p><b>Response: Thank you for your comment.</b></p>		
Imperial Irrigation District	Yes	
Southwest Power Pool Regional Entity	Yes	

Organization	Yes or No	Question 7 Comment
Salt River Project	Yes	
Progress Energy	Yes	
Florida Power & Light Company	Yes	
FPL	Yes	
FMPP	Yes	
Tucson Electric Power	Yes	
Associated Electric Cooperative Inc	Yes	
South Carolina Electric and Gas	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
ISO/RTO Council Standards Review Committee/ Independent Electricity System Operator		<p>We do not have an opinion on whether or not the Background Document provides sufficient clarity to the development of the standard. We do, however, suggest that the SDT consider our comments in Q6, above, and move some of the information from Attachments A and B to or combine with the Background Document, to the Background Document to provide all the technical basis and background behind the elements stipulated in the requirements.</p>
<p><b>Response: Please refer to our response to Question #6.</b></p>		

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8. The SDT has developed a new document titled Attachment B – Process for Adjusting Bias Setting Floor. This document is intended to provide the methodology the ERO will use to reduce the minimum Frequency Bias Setting to become closer to natural Frequency Response. Do you agree that this document provides clear and concise instructions for the ERO to follow? If not, please explain in the comment area.

**Summary Consideration:** The majority of commenters did not like the word “initially” that was used in the proposed standard. They felt that it caused confusion. The SDT modified the attachment to remove the reference to the word “initially” and added other clarifying language to the document.

Some commenters were concerned with how the calculation of FRO for BAs that have load and generation. The intent was that generation-only BAs would base their settings on generation. Traditional BAs would use load. The SDT revised the table to agree with the proposed standard.

One commenter indicated that the standard was measuring AGC. The SDT disagrees.. There may be some AGC influence in the measurement however the SDT believes that this impact is minor. Based on the data received from the Field Trial, the SDT did not see this phenomenon.

A couple of commenters indicated that the methodology used for calculation of the minimum Frequency Bias Setting could be adverse for a single BA interconnection. The SDT explained that to ensure comparable treatment between BAs with fixed Bias Settings, BAs with a variable Bias Setting report their monthly average Bias for the reporting year. This average will be calculated when frequency is greater than 60.036 Hz or less than 59.964 Hz. The average of the 12 months’ Bias values must be equal to or more negative than the Interconnection’s minimum Bias Setting.

Organization	Yes or No	Question 8 Comment
Seattle City Light	Negative	Answer: Yes Comments: o LADWP and SCL note that Attachment B seems to be reasonable.
<b>Response: Thank you for your comment.</b>		
Constellation Energy Commodities Group	No	Should be revisited based on the proposed modifications to the requirements.

Organization	Yes or No	Question 8 Comment
<p><b>Response: The SDT has modified Attachment B to reflect modifications to the requirements and suggested changes from the industry.</b></p>		
MRO NSRF	No	<p>: There could be some confusion caused by the Attachment B due to the use of the word “initially” when the reference is made to the current standard. The drafting team should change the word “initially” to “currently” or strike it to avoid the potential confusion.</p> <p>The second paragraph of Attachment B (which contains the two bullets):The words “initially 1%” in the second bullet contradict with the Table 1 on Attachment B, which states “Initial” and “0.8%”. Suggest deleting the parenthetical in the second bullet as when BAL-003-1 is effective it would be referencing an old Standard version. If the initial minimum is intended to be 1% say so in the Table 1.</p>
<p><b>Response: The SDT has modified Attachment B to reflect your suggested changes.</b></p>		
Texas Reliability Entity	No	<ol style="list-style-type: none"> <li>1. In Attachment B, we <b>suggest removing the paragraph</b> beginning “The BA calculates . . .” because it appears to be background information that conflicts with the methods provided in this version of the standard for determining minimum bias settings.</li> <li>2. Attachment B, Table 1, refers to “0.8% of peak load or generation.” If a BA has both load and generation, will its minimum Frequency Bias Setting be based on its load, its generation, or can it pick the value that it prefers to use?</li> </ol>
<p><b>Response:</b> The SDT agrees and has modified the <b>attachment</b> [MEL34]. <b>Removed from Procedure</b></p> <p>The SDT intended that generation-only BAs would base their settings on generation. Traditional BAs would use load. We have revised the table to agree with the proposed standard.</p>		
Bonneville Power Administration	No	<p>BPA understands the concept and we disagree with it. As the ERO continues to lower the required minimum frequency bias setting for an interconnection, the BA’s that have frequency response higher than the 1% will have a higher percentage of the</p>

Organization	Yes or No	Question 8 Comment
		<p>frequency response of the interconnection.</p> <p>Also, this standard is primarily measuring AGC response, not natural frequency response; therefore not lowering the limit is appropriate.</p>
<p><b>Response: The SDT believes that you may be mixing the Frequency Bias Setting and Frequency Response Measure. As proposed the FRO will be assigned based upon load and generation as defined in Attachment A. Therefore actual Frequency Response will be required to come from the interconnection on that basis. To the extent an entity has a FRM greater than its Interconnection’s minimum Frequency Bias Setting, its Frequency Bias Setting may grow as a percent of the Interconnections total Frequency Bias Setting. However, that is not Frequency Response.</b></p> <p><b>The SDT disagrees with your comment concerning AGC. There may be some AGC influence in the measurement however the SDT believes that this impact is minor. Based on the data received from the Field Trial, the SDT did not see this phenomenon.</b></p>		
Duke Energy	No	<p>Duke Energy suggests that the SDT consider a term other than “Initial’ in the title for Table 1. We suggest “Proposed Frequency Bias Setting” for Table 1. Notwithstanding our suggestion that the criteria/requirements of the minimum FBS in the Attachment be incorporated into the Standard, Duke Energy has the following concerns with what is proposed:</p> <p>As cited in our comments to Question 8 in the last posting (extensive, so not repeated here), the secondary control measures of CPS1, CPS2 and the draft Balancing Authority ACE Limit (BAAL) are tightly coupled to the Frequency Bias Setting (FBS), and a reduction of the FBS will impact the secondary control requirements placed upon the BA. Noted in our response to Question 7 above, the statement on page 9 in the “BAL-003-1 Background Document” is not correct in stating that Attachment B will “ensure there is no negative impact on other Standards”. The gradual reduction of the FBS will proportionally tighten the secondary control limits for each Balancing Authority. Even if the “natural” Frequency Response in the Eastern Interconnection remains unchanged for the next several years, under the process described allowing the ERO to annually adjust the minimum FBS for the Interconnection, the FBS will eventually be reduced to a value approximately 10% above the calculated response in</p>

Organization	Yes or No	Question 8 Comment
		<p>magnitude, cutting the current CPS1, CPS2 and BAAL limits in the Eastern Interconnection on average by more than half. The current FBS for the Eastern Interconnection is approximately minus 6500 MW/0.1Hz, estimated “natural” Frequency Response is perhaps around minus 2400 MW/0.1Hz. Unlike CPS1 and BAAL where the measures are based upon the FBS of the BA only, CPS2 (dependent upon the FBS of the BA and the Interconnection) will be significantly limiting to the degree that no change in a BA’s own Frequency Response could significantly change its CPS2 limit if the Interconnection FBS drops over time as indicated. At least under CPS1 and the draft BAAL, the BA would have an option of improving its Frequency Response, allowing it to increase its FBS and proportionally the CPS1 and BAAL bounds using the FBS.</p> <p>Conclusion from our last comments submitted: Duke Energy does not believe there is a reliability need pushing the industry to tighten secondary control to the degree discussed above simply as a result of reducing the Frequency Bias Setting. If the calculated Frequency Response of the Interconnection stayed at its current level, what would be the justification for tightening the secondary control requirements of CPS1, CPS2 and the proposed BAAL? Duke Energy supports taking more of the error out of the ACE equation by having the FBS closer to the estimated Frequency Response of the Balancing Authority, however, Duke Energy does not believe the result should be a significant increase in secondary control costs to meet the CPS1, CPS2, or draft BAAL requirements. Duke Energy understands the position placed upon this Standard Drafting Team- the secondary control and reserve requirements are not under the scope of the team, however, proper consideration has not been given in Attachment B to the impact lowering the FBS will have on the industry in terms of the requirements placed upon the BA for secondary control and reserve requirements - especially for meeting CPS2. The research discussed in our comments to the last posting support that reducing the FBS while under CPS1 and the draft BAAL may be achievable, however a CPS2 bound cut potentially in half or lower will place unreasonable bounds on a BA, requiring control actions even when the BA may be operating in support of the Interconnection frequency. Given the significant</p>

Organization	Yes or No	Question 8 Comment
		<p>impacts discussed, Duke Energy believes that additional provisions must be in place for the Industry to approve each subsequent revision to the calculation of the minimum Frequency Bias Setting, rather than leave it as a decision made only by the ERO.</p>
<p>Response: We agree with your comment about the word "initial" in Attachment B and have removed the word "initial" from the title to remove the confusion.</p> <p>We believe that your assessments about the effects on CPS2, BAAL and CPS1 are uncertain because there are complex interactions between the Frequency Bias Setting and the ACE values in these measures that use a Frequency Bias Setting.</p> <p>We agree that the words in Attachment B stating "ensure there is no negative impact on other standards" is an overstatement at this point. We have modified language to state the objective is to "allow time to analyze impact<sup>[MEL35]</sup>". This is why we have chosen to go slow with the concept of allowing the frequency bias setting to be reduced below 1% of Peak Load.</p> <p>We agree with your support of taking more of the error out of the ACE equation by making the FBS closer to the estimated Frequency Response of the Balancing Authority; however, we do not agree that the effects of secondary control can be ignored when we make these changes. Therefore we are proposing a "go slow approach" to making this happen and included checks to confirm there are not unexpected influences injected into the CPS-related calculations.</p> <p>Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting 0.9% of peak Load or generation and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.</p> <p>We support your comment related to the ERO working with the Industry to approve each subsequent revision to the minimum FBS. However, it is this drafting team's understanding that the language in the standard is limited to referencing the ERO and the ERO will develop a process to address the needs of the standard. Therefore, no modification has been made to require any specific coordination between the ERO and the Industry.</p>		
Sacramento Municipal Utility District (SMUD)	No	<p>In addition to the requirements, reducing frequency bias obligation results in generation tripping closer to the set point.</p> <p>It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will</p>

Organization	Yes or No	Question 8 Comment
		<p>result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.</p>
<p><b>Response: The SDT is unsure of what your first comment is attempting to say. Therefore the SDT cannot provide a response to your comment without further clarification.</b></p> <p><b>The SDT believes that you may be mixing the Frequency Bias Setting and Frequency Response Measure. As proposed the FRO will be assigned based upon load and generation as defined in Attachment A. Therefore actual Frequency Response will be required to come from the Interconnection on that basis. To the extent an entity has an FRM greater than its Interconnection’s minimum Frequency Bias Setting, its Frequency Bias Setting may grow as a percent of the Interconnection’s total Frequency Bias Setting. However, that is not Frequency Response.</b></p>		
NV Energy	No	<p>In Attachment B, it seems unclear whether the initial FB setting is supposed to be 1% of BA peak load or 0.8% as shown in the table. In general, I was extremely confused about what the required FB setting should be. R5 indicates a percentage of load found in Att B, but Att B indicates the greater of Natural Frequency Response or 1% of peak, and then the table that follows indicates 0.8%. At this point, I have no idea what is being stated for the requirement.</p>
<p><b>Response: The SDT agrees and has modified the attachment.</b></p> <p><b>The SDT intended that generation-only BAs would base their settings on generation. Traditional BAs would use load. We have revised the table to agree with the proposed standard.</b></p>		
Progress Energy	No	<p>PGN supports the collective comments of SERC members. We suggest the SDT consider a term other than “Initial” in the title for Table 1. We suggest “Proposed Frequency Bias Setting” for Table 1</p>
<p><b>Response: The SDT agrees with your comments and has made corresponding modifications to the attachment by removing the word, “initial”.</b></p>		
Independent Electricity	No	<p>Please see our comments under Q6. In brief, we do not agree with including a</p>

Organization	Yes or No	Question 8 Comment
System Operator		process description type of document as part of the standard requirement.
<b>Response: Please refer to our response to Question #6.</b>		
ISO/RTO Council Standards Review Committee	No	Please see our comments under Q6. In brief, we do not agree with including a process description type of document as part of the standard requirement. Process description should be regarded guideline document and not a part of the standard requirement.
<b>Response: Please refer to our response to Question #6.</b>		
Tucson Electric Power	No	Reducing a BAs frequency bias setting may have an adverse impact on recovering from a frequency event once you get past the first 8-10 seconds. A larger bias will allow for actual and sustained AGC generator responses. Industry focus should be on generator governor response within the first 8-10 seconds.
<b>Response: The Standard Drafting Team disagrees with your comment. Full recovery is dependent upon the contingent BA recovering from its loss. However, we do agree that secondary frequency support from the non-contingent BAs may not be as robust.</b>		
Northeast Power Coordinating Council	No	Refer to the first comment in Question 6.
<b>Response: Please refer to our response to Question #6.</b>		
Hydro-Quebec TransEnergie	No	The methodology proposed to compute the Minimum Frequency Bias Setting (in MW/0,1Hz) could be adverse for the Quebec Interconnection. Hydro-Quebec uses a variable Bias that is calculated based upon which generator is online and it's droop setting. Under light load condition, we might have a Bias setting that would be under (in absolute value) than the FRM which is the median value, even though the Bias setting would reflect the grid's frequency response. This method, as proposed, would

Organization	Yes or No	Question 8 Comment
		<p>mandate us to have a larger Bias that what is really needed. Unlike Eastern Interconnection, we are not over biased. By implementing this new methodology, it would make us over biased. Having a too large Bias could lead to system instability, based on the results of studies from our control specialists. The Minimum Frequency Bias Setting should take into account the wide load span that we can face.</p> <p>For the variable bias, we could express the Minimum Frequency Bias Setting as a function of monthly peak loads, and remove the Natural Frequency Response term. In addition, there is a gap between Attachment B and the text in R5. See comment 10 for explanation.</p>
<p><b>Response: To ensure comparable treatment between BAs with fixed Bias Settings, BAs with a variable Bias Setting report their monthly average Bias for the reporting year. This average will be calculated when frequency is greater than 60.036 Hz or less than 59.964 Hz. The average of the 12 months' Bias values must be equal to or more negative than the Interconnection's minimum Bias Setting.</b></p>		
Xcel Energy	No	<p>There could be some confusion caused by the Attachment B due to the use of the word "initially" when the reference is made to the current standard. The drafting team should change the word "initially" to "currently" or strike it to avoid the potential confusion.</p>
<p><b>Response: The SDT agrees with your comment and has modified the attachment to remove the word, "initially".</b></p>		
Florida Power & Light Company	No	<p>There is no technical justification provided either in the attachment or background data for the initial starting value of 0.8%. This is acceptable but is arbitrary.</p> <p>Additionally, the last sentence on page 1 of Attachment B should be changed to read " the ERO must reduce ( in absolute value) the minimum Frequency Bias Settings for BA's within that Interconnection, by 0.1 percentage point from its previous annual value, to better match the Frequency Bias Setting to the natural Frequency Response or provide technical justification for not implementing the reduction</p>
<p><b>Response: You are correct, the starting value is arbitrary. The SDT did not want to make a one step change to immediately reduce</b></p>		



Organization	Yes or No	Question 8 Comment
<p>the minimum Frequency Bias Setting to natural Frequency Response. The SDT believes that a multi-year multi-step process would be better and allows for monitoring the effects on other performance standards.</p> <p>The SDT believes that the end result would be the same. The present wording allows for collaboration between the ERO and other entities/groups. The SDT is also concerned with putting a requirement on the ERO within an Attachment when there is not a reliability problem if it were not to happen.</p>		
SERC OC Standards Review Group	No	We suggest the SDT consider a term other than “Initial’ in the title for Table 1. We suggest “Proposed Frequency Bias Setting” for Table 1
<p><b>Response: The SDT agrees with your comment and has modified the attachment by removing the word, “initial”.</b></p>		
South Carolina Electric and Gas	No	We suggest the SDT consider a term other than “Initial’ in the title for Table 1. We suggest “Proposed Frequency Bias Setting” for Table 1
<p><b>Response: The SDT agrees with your comment and has modified the attachment by removing the word, “initial”.</b></p>		
ISO New England Inc	No	We suggest the SDT to first determine if the materials in the revised Attachment A & B are “Guideline” or Technical Background”, or are they “requirements”. If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as-written Attachment A is a mix bag as it on the one hand describes the ERO’s process for supporting the Frequency Response Standard (FRS), in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM, and on the other hand the BA’s obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which, by the way, is not held responsible for complying with the proposed method. An appendix is not regarded as a mandatory requirement.
<p><b>Response: The process is still being developed at NERC but an Attachment would document processes to be utilized without a measurement saying that you failed the standard.</b></p>		

Organization	Yes or No	Question 8 Comment
Southern Company	No	We suggest using the words, 'Proposed Frequency Bias Setting' in the Title of Table 1 instead of the word, 'Initial'.
<b>Response: The SDT agrees with your comment and has modified the attachment by removing the word, "initial".</b>		
ERCOT	No	While there is no problem with the calculation involved, it is unclear why the SDT elected to assign a grid performance element in this standard to the ERO, who has no functional (registered) role in grid performance. Since this is a cook-book calculation and transfer of data on frequency performance, why not assign it to the BA?
<b>Response: The Attachment B only outlines a process that the ERO is to use when adjusting the minimum Frequency Bias Setting. The attachment does not place any grid performance requirement on the ERO. The SDT also believes that some authority should have oversight over the minimum setting to prevent abuses and assure fairness.</b>		
Seattle City Light	Yes	o LADWP and SCL note that Attachment B seems to be reasonable.
<b>Response: The SDT thanks you for your affirmative response and clarifying comment.</b>		
Energy Mark, Inc.	Yes	Comment 15: This Yes answer assumes that the SDT addresses Comment 13 under Question 6 in these comments.
<b>Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT addressed your Comment #13 under Question #6.</b>		
Ameren	Yes	Considering the comments made regarding R5, in question 2, above, which are:  R5. While we agree with the requirement of R5, it should not be at the expense of changing the value of L10 in BAL-001, R2, which has been accepted by FERC in Order 693. An accommodation should be made so that any changes to the Frequency Bias Setting according to BAL-003, R5, should not affect the value of L10 used in BAL-001, R2.

Organization	Yes or No	Question 8 Comment
<p><b>Response: The SDT thanks you for your affirmative response and clarifying comment. However, the SDT disagrees with your comment. Since L<sub>10</sub> is the function of individual Frequency Bias Settings to the sum of all BA Frequency Bias Settings within an Interconnection and establishes operating boundaries, it would be inappropriate to leave L<sub>10</sub> as is when a Frequency Bias Setting changes.</b></p>		
Los Angeles Department of Water and Power	Yes	LADWP notes that Attachment B seems to be reasonable
<p><b>Response: The SDT thanks you for your affirmative response and clarifying comment.</b></p>		
FPL	Yes	Last paragraph: As stated, would that make the Minimum Frequency Bias Setting 0.7% of peak load or generation? A numerical example shown would help clarify this paragraph.
<p><b>Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT has added an example to the Background Document.</b></p>		
Southwest Power Pool Regional Entity	Yes	Need to clarify that 2012 Bias setting will be based on 1% of peak load or generation until approval of BAL-003-1 by FERC establishing the .08% of peak load or generation minimum threshold.
<p><b>Response: We agree and we have endeavored to do so. The SDT does point out that the proposed minimum for the first year once approved by FERC is 0.9% not 0.08%.</b></p>		
Associated Electric Cooperative Inc	Yes	This is a very important document, providing bounds and rationale for and future changes, as well as initial settings going into ballot. As such, it is AECI's understanding that, upon going into effect, this BAL-003-1 will utilize these initial settings.
<p><b>Response: The SDT thanks you for your affirmative response and clarifying comment.</b></p>		
Imperial Irrigation District	Yes	

Organization	Yes or No	Question 8 Comment
SPP Standards Review Group	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Salt River Project	Yes	
FMPP	Yes	
American Electric Power	Yes	
Cleco Corporation	Yes	
Manitoba Hydro	Yes	
Great River Energy	Yes	
Keen Resources Asia Ltd.	Yes	

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9. The SDT has provided an additional spreadsheet, FRS Form 2, to assist the Balancing Authority in providing the data needed to comply with the proposed standard. Do you agree that this spreadsheet is useful and the instructions are meaningful? If not, please explain in the comment area.

**Summary Consideration:** Many of the commenters expressed concern with the fact that the Excel Spreadsheets that were required to be used were in a newer version of Excel than their company was presently using. In response, the SDT developed Excel Spreadsheets that are compatible with earlier versions of Excel [MEL36].

A couple of commenters expressed concern that the Excel Spreadsheets did not contain all of the information necessary to comply with the analysis required (timing of the event (hour, minute, second). Form 1 contains the time of the event including the hour, minute and second for t(0) and a graph of frequency data for each event in the list. The time for each BA’s t(0) may vary from this time due to different sample rates of data and physical proximity to the contingency. Since this standard does not identify a “A Point” or “B Point” but calculates an “A Value” and “B Value”, providing an exact time for these provides little value. T(0) is the focus of the measurement process and is the first observed change in frequency of the event. Also added to Form 1, the BA can enter the time zone of its data and the time of t(0) will be converted to the correct time in that zone. We agree that the proper selection of t(0) is important. This can be viewed on the “Graph 20 to 52s” worksheet. When set correctly, the first change in frequency of the event will be exactly in the center of the graph on the vertical grid line.

Some commenters felt that it would be useful if the SDT could develop a completed form as an example to help entities better understand the methodologies used in the form. Form 2 contains actual data for frequency and NAI of an event. Sample data was added for each of the adjustments to demonstrate their use and impact on the analysis.

A couple of commenters question the meaning of “master event list” in FRS Form 2. The “Master event list” refers to the event list contained in each Interconnection’s Form 1.

Organization	Yes or No	Question 9 Comment
Seattle City Light	Negative	Answer: No Comments: o LADWP and SCL note that Form 2 is not compatible with prior versions of Excel-it won’t even open in Excel 2003 (which is still widely used)- and requests that all spreadsheets and calculation tools developed under 2007-12 be revised to support common software of the past 10 years.

Organization	Yes or No	Question 9 Comment
<p>Response: <b>Excel 2003 versions of all forms are being developed.</b></p>		
Seattle City Light	No	<p>o LADWP and SCL note that Form 2 is not compatible with prior versions of Excel-it won't even open in Excel 2003 (which is still widely used)-and requests that all spreadsheets and calculation tools developed under 2007-12 be revised to support common software of the past 10 years.</p>
<p>Response: <b>Excel 2003 versions of all forms are being developed.</b></p>		
Associated Electric Cooperative Inc	No	<p>AECI believes the SDT could spare our industry both confusion and inconsistency, by specifying that identified Interconnection Disturbances include both Point A and Point B to the hour, minute, and second. While this introduces some risk of Entities over-automating their data-reports, the benefits for Eastern Interconnection respondents would be tremendous. Cautions and disclaimers should be placed on both Form 1 and Form 2, to assure respondents manually inspect their frequency data and pinpoint the specific inflection-point samples.</p>
<p>Response: Form 1 contains the time of the event including the hour, minute and second for t(0) and a graph of frequency data for each event in the list. The time for each BA's t(0) may vary from this time due to different sample rates of data and physical proximity to the contingency. Since this standard does not identify an "A Point" or "B Point" but calculates an "A Value" and "B Value", providing an exact time for these provides little value. T(0) is the focus of the measurement process and is the first observed change in frequency of the event. Also added to Form 1, the BA can enter the time zone of its data and the time of t(0) will be converted to the correct time in that zone. We agree that the proper selection of t(0) is important. This can be viewed on the "Graph 20 to 52s" worksheet. When set correctly, the first change in frequency of the event will be exactly in the center of the graph on the vertical grid line.</p>		
Bonneville Power Administration	No	<p>BPA believes the form is not easily understood and is overly complicated for what it is trying to accomplish. BPA believes the form might work for an internal evaluation, just not for an external audit. Compliance is based on this form. BPA believes the standard needs to be simplified and possibly returned to a data gathering standard.</p>

Organization	Yes or No	Question 9 Comment
<p>Response: The addition of “Adjustments” to the analysis did add complexity to the Form. These were added based on comments received from the industry on previous postings. Some of these “Adjustments” may be removed as the field trial progresses if they are not utilized. In the latest Form 2, version 6, the multiple time period averages were removed since the final average period was selected based on the results of the first round of the field trial evaluated last fall. However, Form 2 is important to the standard in that it achieves the requirement of measuring frequency response in the same manner for all Interconnections. Returning Form 2 with Form 1 allows validation of the selection of t(0) which is critical for this requirement.</p> <p>The SDT does not believe that it can revert back to a “data gathering” standard. The SDT is responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012.</p>		
FPL	No	<p>FRS Form 2 - Two-second Sample DataInstructions tab/worksheet: What is referred to as or meant by the ‘master event list’?</p> <p>4. - Regarding 2 second sample rate for 25 minutes starting 2 minutes before event begins and 15 minutes after it begins, does this add up to 25 minutes or are additional minutes being required for collection? Also, FPL can report frequency at this rate, but can only report load in MW every four seconds. Move to 4 second sample rate.</p> <p>6-8. - Possible to add button to auto-populate cells C8 and C11 in ‘Entry Data’ tab from the new column C and cell identifying the desired frequency change time and simplify these steps?</p> <p>10. - Clarify where the “Copy” button is. Is it the one in the ‘Data’ tab or worksheet?</p> <p>Entry Data tab/worksheet: Step 6 should also be or be moved to the “Instructions” worksheet. Are the values in column C in the “Data” worksheet labeled “Total Lost Generation” the same as those in column AQ in the “Evaluation” worksheet? If so, why are they not both labeled “Net Actual Interchange”?</p> <p>What is the definition of “Non Conforming Load” in column E?</p>
<p>Response: “Master event list” refers to the event list contained in each Interconnection’s Form 1.</p>		

Organization	Yes or No	Question 9 Comment
		<p>The inconsistency in the data sample totals has been corrected. The absolute minimum amount of data required for the full analysis is two minutes before the beginning of the event to 15 minutes after the beginning of the event. The calculation rate of “Load” can be at a different rate than the AGC scan rate. The Load data is not used in measuring performance. The variability of Load can impact measured performance and can be observed on the “BA Load Dampening” worksheet graph. On some Interconnections, load dampening can be observed in the data. Using the historian “data sample” collection option, it will fill the spreadsheet with the same value of Load, changing at the calculation rate.</p> <p>The “auto populate” of cells C8 and C11 is a good idea. A couple BAs did this during the first phase of the field trail. The problem is that the event time of t(0) in column C was set using 2 second scan data in one part of the Interconnection and the beginning of the event may be shifted one or two scans when frequency is scanned less often. This would make this automation difficult for the value in C8. It is critical for the measure for t(0) be set correctly. The value of C11 is less critical and is not used in the initial primary Frequency Response Measure. It is only used to demonstrate delivery of primary frequency response during the frequency recovery period.</p> <p>The location of the “Copy” button has been clarified.</p> <p>Step 6 on the “Data Entry” worksheet was added to the “Instructions” worksheet. The value in column C in the “Data” worksheet labeled “Total Lost Generation” is for single BA Interconnections only. It takes the place of “Net Actual Interchange” for multiple BA Interconnections. Column “AO” on the “Evaluation” worksheet is not the same as the “Contingent BA Lost Generation” data on the “Evaluation” worksheet. The “Contingent BA Lost Generation” data is only used by multiple BA Interconnection BAs not Single BA Interconnections. The “Data” worksheet for the “Single BA Interconnection” Forms has an n/a in columns G, H and I and should not be used by BAs in these Interconnections. This is noted on their “Instructions” worksheet. This should explain why they are not labeled the same.</p> <p>Non-conforming Load is Load that changes abnormally different than the conventional diurnal load pattern of a Balancing Authority Area. Non-conforming Load becomes significant when the net change within a few minutes is greater than a BA’s L<sub>10</sub> limit. The importance here is that this Load change can be ten times larger than some BAs’ FRO and makes measuring the SEFRD inaccurate. An example of non-conforming load would be an arc furnace of a significant size.</p> <p>Thank you for your comments and the effort to find each of these items.</p>
ISO/RTO Council Standards Review Committee	No	If we are not mistaken, Form 2 is added as the last sheet in the Form 1 spreadsheet file. Apart from that, however, there are other sheets added to the previous Form 1. But this Comment form makes no mention of the changes, nor is there a question in



Organization	Yes or No	Question 9 Comment
		<p>the Comment Form asking whether the additional information should be requested. We believe this is a significant change to the standard and many commenters may have missed the opportunity to comment on it. Compared to the previous version, Form 1 has been significantly expanded to include not only additional sheets but much more comprehensive data requirements even on the Data Entry sheet itself. This makes data submission a very time-consuming task but the justification for requiring detailed data entry has not been provided.</p> <p>We question the need for such expansion on data entry requirements. We have yet to see the reason for expanding Form 1 in assisting a BA to provide the data needed to comply with the standard, hence we do not see how adding a Form 2 can help in that regard. We suggest the SDT to keep data requirements to only what is minimally needed to support the FRS reporting process. Where the SDT deems additional data entry sheets to be necessary, it should provide the rationale for expanding from a 2 sheet form into a multiple sheet form for additional data collection. Where the SDT deems the additional data sheet or information not necessary to support FRS reporting, then we suggest the SDT to hide those pages not required for the standard so as to avoid confusion, and/or to remove those analytical pages not directly used in the standard.</p>
<p><b>Response:</b> The SDT points out that there are no additional data requirements. It is possible that you are seeing more spreadsheets due to them being unhidden.</p> <p>Form 2 is a separate stand-alone workbook. Form 1 does have a worksheet labeled “BA Form 2 Event Data” that will contain the single event data from each of the BA’s Form 2s. Two additional worksheets were added to Form 1 and several worksheets were deleted. The “Time Zone Ref” worksheet was added to allow the ability of the BA to enter the time zone of its data and the spreadsheet will calculate the local time of the event from the UTC time. This was added for the convenience of the BA in collecting the correct data for each event and does not require additional data from the BA. The second worksheet added was a worksheet that displays graphs of frequency for each event and the t(0) selected correctly. This was added to aid the BA with data collection and the selection of t(0) since this seemed to be one of the biggest problems during the first phase of the field trial. This graph worksheet does not require the BA to do anything. It is not used in the analysis and can be deleted. Deleting this worksheet will greatly reduce the size of Form 1. None of the data requirements on Form 1 or Form 2 have changed from previous</p>		

Organization	Yes or No	Question 9 Comment
<p>versions. The absolute minimum data needed for this standard is the date/time, frequency and NAI in columns A, B and C of the “Data” worksheet in Form 2. Columns D through I have been totally optional and can be left blank. Column J is the Bias setting in the ACE equation and is important to BAs that utilize variable Bias. Column K, BA Load, was added by the drafting team in the beginning to see if Load Dampening could be measured as this has been done for several years on one Interconnection. Column L of the “Data” worksheet is the only optional data that the BA should use when it is the contingent BA during any of the events evaluated. Utilizing this data will allow the BA’s SEFRD to be calculated correctly and give the BA a full sample set for the annual median calculation. Form 2 is necessary to standardize the measurement process on all Interconnections. You are free to hide any analytical worksheets on Form 1 and Form 2. You can do this on your “master” Form 2 and then build each Form 2 for each event using this master. These additional worksheets are available for BAs to utilize if they find that their performance is below the FRO and will aid the analysis of the contributing causes.</p>		
<p>Independent Electricity System Operator</p>	<p>No</p>	<p>If we are not mistaken, Form 2 is added as the last sheet in the Form 1 spreadsheet file. Apart from that, however, there are other sheets added to the previous Form 1. But this Comment form makes no mention of the changes, nor is there a question on the additional information requested. We have a concern over this omission of attention or oversight. Compared to the previous version, Form 1 has been significantly expanded to include not only additional sheets but much more comprehensive data requirements even on the Data Entry sheet itself. This makes data submission a very time-consuming task but the justification for requiring detailed data entry has not been provided. We question the need for such expansion on data entry requirements. We have yet to see the reason for expanding Form 1 in assisting a BA to provide the data needed to comply with the standard, hence we do not see how adding a Form 2 can help in that regard. We suggest the SDT to look at the basic need for data submission that would suffice to support the FRS reporting process. Where the SDT deems additional data entry sheets to be necessary, it should provide the rationale for expanding from a 2 sheet form into a multiple sheet form for additional data collection.</p>
<p><b>Response: The SDT points out that there are no additional data requirements. It is possible that you are seeing more spreadsheets due to them being unhidden.</b></p>		

Organization	Yes or No	Question 9 Comment
<p>Form 2 is a separate stand-alone workbook. Form 1 does have a worksheet labeled “BA Form 2 Event Data” that will contain the single event data from each of the BA’s Form 2s. Two additional worksheets were added to Form 1 and several worksheets were deleted. The “Time Zone Ref” worksheet was added to allow the ability of the BA to enter the time zone of its data and the spreadsheet will calculate the local time of the event from the UTC time. This was added for the convenience of the BA in collecting the correct data for each event and does not require additional data from the BA. The second worksheet added was a worksheet that displays graphs of frequency for each event and the t(0) selected correctly. This was added to aid the BA with data collection and the selection of t(0) since this seemed to be one of the biggest problems during the first phase of the field trial. This graph worksheet does not require the BA to do anything. It is not used in the analysis and can be deleted. Deleting this worksheet will greatly reduce the size of Form 1. None of the data requirements on Form 1 or Form 2 have changed from previous versions. The absolute minimum data needed for this standard is the date/time, frequency and NAI in columns A, B and C of the “Data” worksheet in Form 2. Columns D through I have been totally optional and can be left blank. Column J is the Bias setting in the ACE equation and is important to BA’s that utilize variable Bias. Column K, BA Load, was added by the drafting team in the beginning to see if Load Dampening could be measured as this has been done for several years on one Interconnection. Column I of the “Data” worksheet is the only optional data that the BA should use when it is the contingent BA during any of the events evaluated. Utilizing this data will allow the BA’s SEFRD to be calculated correctly and give the BA a full sample set for the annual median calculation. Form 2 is necessary to standardize the measurement process on all Interconnections. You are free to hide any analytical worksheets on Form 1 and Form 2. You can do this on your “master” Form 2 and then build each Form 2 for each event using this master. These additional worksheets are available for BAs to utilize if they find that their performance is below the FRO and will aid the analysis of the contributing causes.</p>		
Los Angeles Department of Water and Power	No	LADWP notes that Form 2 is not compatible with prior versions of Excel-it won’t even open in Excel 2003 (which is still widely used)-and requests that all spreadsheets and calculation tools developed under 2007-12 be revised to support common software of the past 10 years.
<p><b>Response:</b> Excel 2003 versions of all forms are being developed.</p>		
Tucson Electric Power	No	TEP feels that Form 2 is a useful tool for internal BA use and should not be used for compliance purposes.
<p><b>Response:</b> Form 2 is not intended to be used to reflect compliance but rather for consistency in reporting.</p>		

Organization	Yes or No	Question 9 Comment
<p>Form 2 was developed so consistent analysis of each event could be validated. During the first round of the field trial, many BAs selected the incorrect t(0), some provided data that was filtered or utilized data compression techniques that caused the analysis to be incorrect. With Form 2, the selection of t(0) can be quickly evaluated and data quality reviewed. The proper selection of t(0) can be made and Form 1 corrected providing validated consistent results.</p>		
MRO NSRF	Yes	: It would be useful if the drafting team could develop a completed form as an example to help entities better understand the methodologies used in the form
<p><b>Response: All versions of Form 2 contain actual data for frequency and NAI of an event. Sample data was added for each of the adjustments to demonstrate their use and impact on the analysis.</b></p>		
Xcel Energy	Yes	It would be useful if the drafting team could develop a completed form as an example to help entities better understand the methodologies used in the form.
<p><b>Response: All versions of Form 2 contain actual data for frequency and NAI of an event. Sample data was added for each of the adjustments to demonstrate their use and impact on the analysis.</b></p>		
Ameren	Yes	We agree that the spreadsheet is meaningful, but still needs to be vetted through the field trial process, with improvements made based on experience in its use.
<p><b>Response: We completely agree.</b></p>		
Imperial Irrigation District	Yes	
Northeast Power Coordinating Council	Yes	
SERC OC Standards Review Group	Yes	
SPP Standards Review Group	Yes	

Organization	Yes or No	Question 9 Comment
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Progress Energy	Yes	
Southern Company	Yes	
Energy Mark, Inc.	Yes	
Florida Power & Light Company	Yes	
FMPP	Yes	
ISO New England Inc	Yes	
NV Energy	Yes	
American Electric Power	Yes	
South Carolina Electric and Gas	Yes	
Cleco Corporation	Yes	
Manitoba Hydro	Yes	
Constellation Energy Commodities Group	Yes	

Organization	Yes or No	Question 9 Comment
Great River Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Duke Energy	Yes	
Keen Resources Asia Ltd.	Yes	

DRAFT

10. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard BAL-003-1.

**Summary Consideration:** Many of the commenters referenced other questions in the comments. The SDT asked them to review the response to those earlier questions rather than repeating the responses here.

Several commenters pointed out that there was a discrepancy between the Background Document and Attachment A regarding the calculation of the BA FRO. The SDT has corrected the reference so both documents agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.

Several other commenters indicated that Supplemental Regulation Service was not an appropriate method to provide Frequency Response. The SDT agrees that it is inappropriate to expect supplementary regulation to transfer Frequency Response successfully, however the SDT did not want to prevent any innovative solution that will transfer Frequency Response through the use of a pseudo-tie among Balancing Authorities. Also, the SDT believes that Balancing Authorities exchanging Supplementary Regulation via a pseudo-tie have to be consistent in the removal or inclusion of Supplementary Regulation in their actual net interchange measurement as well as in all events across the measurement period.

Many commenters were concerned that the BA could be responsible for supplying an infinite amount of Frequency Response. They indicated that a BA could not prepare for this in its planning process. The SDT agrees that the proposed standard was not clear on this subject and added language in the “Criteria for Selection of Events” section of the revised Attachment A to limit the amount of Frequency Response a BA would be required to provide in order to be compliant with the standard.

Some commenters were concerned with the wording in Requirement R5. They indicated that the wording needed to say “greater than or” instead of “at least”. The SDT removed the requirement and combined it with the revised Requirement R2 and the new Requirement R3<sup>[MEL37]</sup>.

Many commenters did not agree with requiring the BA to provide Frequency Response. The NERC Functional Model and FERC both cited the BA as the responsible entity for providing Frequency Response. There are several different methods available to the BA to provide Frequency Response and the SDT has included these in the Background Document.

Some commenters were concerned with the threshold that the SDT recommended for the Eastern Interconnection. Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for the higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the Eastern Interconnection to continuously carry about 4,000 MW of frequency

responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.

A few commented did not agree with lowering the minimum Frequency Bias Setting. Early research by Nathan Cohn on interconnected power system operations found that control is optimum if a BA’s Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased. The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in Attachment B. The attachment manages a “go slow” approach to making this happen **and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations.** Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting t 0.9% of peak Load or generation and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. **The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.**

Some commenters had concerns about the use of the RSG as a means to provide Frequency Response, and the SDT modified the Background Document to further explain how an RSG (now FRSG) could supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”

A couple of commenters indicated that the median was not the proper method to use for the calculation of the FRM. Statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA’s Frequency Response. While the median is not perfect, the median approaches a BA’s typical performance after 15-20 observations and more observations give a higher confidence in the estimate of the BA’s performance.

Organization	Yes or No	Question 10 Comment
MRO NSRF	Negative	It is not clear if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of FR expected on a total basis. Balancing Authorities need to know for how many tenths of a hertz they are to respond so they



Organization	Yes or No	Question 10 Comment
		<p>can determine how to plan to meet this requirement. The documents do not appear to provide any boundary on the maximum amount of FR that a BA will provide, i.e. it is not clear what will happen if an event occurs in the Eastern Interconnection that causes the frequency to drop to less than 59.6 Hz (e.g. what if freq dips to 59.0? Is the BA expected to provide a limitless amount of frequency response?).</p> <p>Also, is that event excluded from the list used to calculate the Balancing Authorities' response or is it included with an expectation that it counts the same as any other event. Without a clear statement of what is expected, including whether there is a limit on that expectation or not, the Balancing Authorities cannot know what is expected of them and therefore cannot plan appropriately.</p> <p>In the first paragraph of R5 delete "at least" and replace with "greater than or". This phrase would now read "...absolute value is greater than or equal to one of the following:" "Equal to or greater than" accurately identifies the expectation, the current phrasing will lead to confusion and mis-interpretation.</p> <p>Bullet #1 of R5: The minimum % is based upon the "estimated yearly Peak Demand". During the NERC webinar it was mentioned that this minimum would move to being based on historical reporting of Peak Demand. Where does the SDT stand on this item? Please provide clarification.</p>
<p><b>Response:</b> The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</p> <p>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3 [MEL38].</p> <p>The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</p>		
Muscatine Power & Water	Negative	"MPW agrees with the comments submitted by the MRO-NSRF."

Organization	Yes or No	Question 10 Comment
		<p>Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</p> <p><b>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p> <p>The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</p>
JDRJC Associates	Negative	Support Midwest ISO Comments
		<p>Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</p> <p><b>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p> <p>The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</p>
Lincoln Electric System	Negative	Please see comments submitted by the MRO NSRF. (See comments for Question 5 submitted by the MRO NSRF.)
		<p>Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</p> <p><b>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p> <p>The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</p>

Organization	Yes or No	Question 10 Comment
Madison Gas and Electric Co.	Negative	Please see the MRO NSRF comments
<p>Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</p> <p><b>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p> <p>The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</p>		
Midwest Reliability Organization	Negative	Please see the comments submitted by MRO NSRF. As MRO Sector 10 we agree with MRO NSRF position and recommendation to vote negative for this ballot.
<p>Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</p> <p><b>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p> <p>The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</p>		
Muscatine Power & Water	Negative	"MPW agrees with the comments submitted by the MRO-NSRF."
<p>Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</p> <p><b>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p> <p>The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is</p>		

Organization	Yes or No	Question 10 Comment
<p>proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</p>		
<p>Nebraska Public Power District</p>	<p>Negative</p>	<p>NPPD joins it's comments with comments submitted by the Midwest Reliability Organization - NERC Standards Review Forum (MRO NSRF) submitted on December 8, 2011.</p>
<p>Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</p> <p><b>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p> <p>The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</p>		
<p>Omaha Public Power District</p>	<p>Negative</p>	<p>Please see MRO's comments submitted via Comment Form.</p>
<p>Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</p> <p><b>The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.</b></p> <p>The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.</p>		
<p>FirstEnergy Corp.; FirstEnergy Energy Delivery; FirstEnergy Solutions; Ohio Edison Company</p>	<p>Abstain</p>	<p>FirstEnergy appreciates the hard work of the drafting team but needs more time to review the standard with internal business units and with our RTO. Therefore at this time we must abstain.</p>

Organization	Yes or No	Question 10 Comment
<p>Response: The SDT thanks you for your clarifying comment.</p>		
	<p>Abstain</p>	<p>As a qualified professional statistician I abstain from voting "affirmative" or "negative" on this standard because it violates two fundamental statistical best practices.</p> <p>1. In the Standard, the definition of Frequency Response Measure (FRM) is statistically wrong. The median is an improper statistical measure of Frequency Response because --it truncates large excursions which are the specific subject of Frequency Response control, not normal operating frequency errors which are self-correcting and are the subject of CPM control; --it is non-linear; --it is non-summable over the interconnection; in other words, the individual BA medians don't add up to the interconnection median, in complete incompatibility with CPM control which requires summability of BA performances into the interconnection's performance. Moreover, it is mathematically impossible to sum the medians of the BAs in a Reserve Sharing Group (RSG) into the RSG's median: in other words, the RSG's median cannot represent the sum of the medians of its members. The last paragraph on page 5 of the Background Document is patently wrong, invented, and supported in no probability &amp; statistics literature whatsoever. As a practicing statistician, I hereby give testimony to the utter falsehood of the statement that "In general, statisticians use the median as the best measure of central tendency when a population has outliers." (See <a href="http://www.robertblohm.com/BestStatistic.doc">http://www.robertblohm.com/BestStatistic.doc</a> for an explanation of "best statistic" which is a highly technical and central topic in modern probability theory and statistics.) Also, "outliers" are falsely and rhetorically claimed to be "noise" when in fact they are the "events" that are the specific subject of Frequency Response. It is well known that they do not "fit" a normal distribution. They are distinct from the normal operating errors that are the subject of CPM control. The paragraph does correctly conclude that the linear regression more accurately incorporates outliers than the median does, although the paragraph uses rhetoric by calling this improvement "skew" as if it is distortionary when, in fact, the</p>

Organization	Yes or No	Question 10 Comment
		<p>median distorts the reality.</p> <p>2. The sample pre-selection described in Attachment A, Event Selection, Criteria 2 &amp; 7, violates the fundamental statistical procedure of unbiased sampling. A population is governed by a single "process" which, when stationary, is represented by a fixed probability distribution. In this case the population is several years of events (which are the subject of Frequency Response), not of normal operating control errors which are the subject of CPM control. A sample is governed by a single process that approximates the process governing the population as the sample gets larger, in this case if it includes several years of data. Samples are measured "as they come", no triage/filtering allowed, and they are called "stratified" when their distribution approximates the population distribution. Unlike normal operating errors, samples of events are not evenly distributed over a year. The attempt in criteria 2 &amp; 7 to pre-select only certain events, and not others, in such a way that the selected events occur evenly throughout the year, is patently wrong because it is trying to "fit" events into a process (even distribution over time) that does not govern events, but that instead governs normal operating errors that are the subject of CPM control, not of this Frequency Response standard. In other words, criteria 2 &amp; 7 confuse Frequency Response with CPM, and events with normal operating errors. The result is a false, biased sample which destroys the integrity of this standard. Paragraph 4 on page 5 of the Background Document, on the other hand, provides a statistically correct description of event selection without sample pre-selection and should followed instead of the erroneous criteria 2 &amp; 7 in Attachment A. The reason I do not vote "negative": the risk-based approach to determining FRM, that the Background Document mentions in paragraph 4 of page 4 is being evaluated by the drafting team for application in this standard, should be considered for deployment as soon as possible to replace the administered method currently proposed in this standard, because the administered method lacks any technical justification. No such justification was ever attempted in the development of this standard. The administrative method of determining FRM is therefore but a highly dubious "quick fix" until the risk-based method is evaluated and implemented. The administrative</p>

Organization	Yes or No	Question 10 Comment
		<p>method is in fact perverse because it discourages BAs from reducing their contribution to frequency error by refusing to reduce the BA's FRO accordingly, and because it encourages BAs to contribute to frequency error without increasing their FRO.</p>
<p><b>Response: The word “average” is a generic term to represent central tendency. The term is often used <u>synonymously</u> with the arithmetic “mean”.</b></p> <p><b>The issue with measuring Frequency Response is that a BA’s calculated performance (as opposed to actual performance) is highly variable event to event. This is particularly true for a single BA in a multi-BA Interconnection.</b></p> <p><b>Calculated Frequency Response has a very large noise to signal ratio. A 5,000 MW BA in the East typically is only called to contribute about 10-15 MW for the loss of a large unit. Its minute to minute Load changes can easily wash this contribution out. An arithmetic mean or regression analysis will be influenced by noise-induced outliers.</b></p> <p><b>Statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA’s Frequency Response.</b></p> <p><b>A regression would be appropriate if you were trying to forecast “calculated” frequency response for a BA in a multi-BA Interconnection.</b></p> <p><b>While not perfect, the median approaches a BA’s typical performance after 15-20 observations. More observations give a higher confidence in the estimate of the BA’s performance.</b></p>		
<p>Associated Electric Cooperative, Inc.</p>	<p>Affirmative</p>	<p>Please see comments submitted by John Bussman of AECl. Thanks, Chris Bolick</p>
<p><b>Response: Please refer to our earlier question responses to Mr. Bussman’s comments.</b></p>		
<p>Southwest Power Pool, Inc.</p>	<p>Negative</p>	<p>Please refer to the IRC Standards Review Committee comments which SPP is a party to for our concerns and recommendations for this standard.</p>

Organization	Yes or No	Question 10 Comment
<p><b>Response: The SDT cannot find any comments submitted by the IRC Standards Review Committee.</b></p>		
<p>City Utilities of Springfield, Missouri</p>	<p>Affirmative</p>	<p>SPRM supports the comments from SPP.</p>
<p><b>Response: The SDT cannot find any comments submitted by the IRC Standards Review Committee.</b></p>		
<p>Oklahoma Gas and Electric Co.</p>	<p>Affirmative</p>	<p>See comments submitted by the Southwest Power Pool</p>
<p><b>Response: The SDT cannot find any comments submitted by the IRC Standards Review Committee.</b></p>		
<p>Electric Reliability Council of Texas, Inc.</p>	<p>Affirmative</p>	<p>The Applicability of BAL-003-1 should be clarified. Specifically, Section 1.2 should be changed from “Reserve Sharing Groups (where applicable)” to “Reserve Sharing Group whose intent includes meeting Frequency Response Obligations”.</p> <p>Regarding Data Retention:</p> <ol style="list-style-type: none"> <li>1. As the standard is currently drafted, both the BA and the RSG would be required to retain data or evidence to show compliance with requirements R1 and M1. It is unclear whether this is the intention, or whether it would be acceptable that just one or the other would maintain such records.</li> <li>2. In the first and second paragraph, the reference to ‘three calendar years’ should be specified to be the ‘previous three calendar years’.</li> <li>3. In the third paragraph, it should be clarified who is required to keep information related to non compliance if the BA belongs to an RSG – the BA or the RSG or both.</li> <li>4. In the fourth paragraph, it should be clarified for what length of time the last audit records must be retained.</li> </ol>
<p><b>Response: The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.” The SDT has modified the Background Document to further</b></p>		



Organization	Yes or No	Question 10 Comment
<p>explain how an RSG (now FRSG) can be used to supply Frequency Response.</p> <p>1 &amp; 3 - The SDT believes that the reporting entity would be the responsible entity to maintain records. The SDT also believes that once a BA has declared itself as part of an FRSG then the FRSG would be the responsible entity with the obligation to maintain records.</p> <p>2 - The SDT agrees with your second comment and has made this modification.</p> <p>4 – The last audit record should be kept until the next audit.</p>		
Midwest ISO, Inc.	Affirmative	We would like to thank the drafting team for developing a standard responsive to the FERC Orders.
<p><b>Response: The SDT thanks you for your affirmative response and clarifying comment.</b></p>		
SCE&G	Affirmative	We feel that frequency response is a function of a contingency event and the Purpose Statement should recognize this relationship. We suggest the following insertion in the Purpose Statement. Purpose: To require sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations (due to a contingency event) and supporting frequency until the frequency is restored. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.
<p><b>Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT believes that the Purpose Statement you are recommending is basically the same as what the SDT is proposing. For this reason the SDT has decided to propose their Purpose Statement for use in the proposed standard.</b></p>		
SERC Reliability Corporation	Affirmative	Please see comments submitted by the SERC Operating Committee standards subgroup for technical suggestions to improve the standard.
<p><b>Response: Please refer to the earlier question for the SDTs responses.</b></p>		

Organization	Yes or No	Question 10 Comment
Tennessee Valley Authority	Affirmative	Comments submitted by SERC OC Standards Review Group. TVA votes affirmative with comments previously submitted by SERC.
<b>Response: Please refer to the earlier questions for the SDTs responses.</b>		
Louisville Gas and Electric Co.	Negative	We support the comments in the SERC OC Standards Review Group Comments.
<b>Response: Please refer to the earlier questions for the SDTs responses.</b>		
AEP, AEP Marketing, AEP Service Corp.	Negative	AEP's negative ballot is primarily due to our concerns regarding R1. Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
<b>Response: Please refer to our response for Question #1.</b>		
Alberta Electric System Operator	Negative	<p>Besides the standard, the posting has two attachments, supporting material and two forms. It is not clear how enforcement will be applied given the array of explicit and implicit requirements throughout this package, and the use of undefined terminology, which will be subject to interpretations.</p> <p>In the SDT response to our comments to the first draft of this standard it was stated that "The expectation is events will be selected by the Balancing Authorities. The Balancing Authority may exclude events from consideration for specific conditions such as data quality issues." Based on the SDT's response, it is our understanding that, for the purpose of the FRM calculation, BAs could exclude or include events based on specific conditions consideration, such as data quality or event suitability (e.g. BA separation from the Interconnection). However, the standard as currently drafted, does not have any provisions to this effect. Please include such provisions in the body of the standard.</p>
<b>Response: The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to</b>		

Organization	Yes or No	Question 10 Comment
<p>be attached to the standard such that it cannot be changed without input from the industry.</p> <p>The SDT recognizes that data may not be available for specific events and therefore has provided in FRS Form 1 a means to exclude an event. Additionally if an entity has separated from an Interconnection this could be reason for excluding that event from its FRM calculation since the frequency it would be responding to would not be the Interconnection wide frequency. The risk caused by excluding events is that the measurement process has shown that a limited number of events does not provide suitable calculation.</p>		
<p>Ameren Energy Marketing Co.; Ameren Services</p>	<p>Negative</p>	<p>We believe that this is good start to a worthwhile standard, but the following issues need to be addressed in this standard:</p> <p>(1) The FRM methodology has not been fully vetted through the field trial process.</p> <p>(2) Adjusting the minimum of the Frequency Bias Setting, while an appropriate adjustment for AGC control in the ACE equation, should not be at the expense of L10 as used in BAL-001, R2.</p> <p>(3) The absence of any resource specific frequency response requirement in NERC standards is an issue that must be address somewhere. As the resource portfolio of our industry changes (expedited by recent EPA rulemaking), the resources used for traditional primary frequency response are becoming a lower percentage of the mix. New resources and existing resources that have not provided primary frequency response need to be incorporated into the available frequency response discussion.</p> <p>(4) BAL-003 is only applicable for an interconnected system, conditions that are created by islanding and other emergencies are not address here (nor should they), but need to be address within the EOP family of standards, so that adequate primary frequency response is available during emergency situations [MEL39].</p>
<p>Response: (1) – The issue with measuring Frequency Response is that a BA’s calculated performance (as opposed to actual performance) is highly variable event to event. This is particularly true for a single BA in a multi-BA Interconnection.</p> <p>Calculated Frequency Response has a very large noise to signal ratio. A 5,000 MW BA in the Eastern Interconnection typically is only called to contribute about 10-15 MW for the loss of a large unit. Its minute to minute Load changes can easily wash this contribution</p>		

Organization	Yes or No	Question 10 Comment
		<p>out. An arithmetic mean or regression analysis will be influenced by noise-induced outliers.</p> <p>Statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA’s Frequency Response.</p> <p>A regression would be appropriate if you were trying to forecast “calculated” frequency response for a BA in a multi-BA Interconnection.</p> <p>While not perfect, the median approaches a BA’s typical performance after 15-20 observations. More observations give a higher confidence in the estimate of the BA’s performance.</p> <p><b>(2) - The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in Attachment B. The attachment manages a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations.</b></p> <p>Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting to be 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. <b>The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.</b></p> <p><b>(3) - The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</b></p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient Frequency Response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a</p>

Organization	Yes or No	Question 10 Comment
<p>need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>(4) – The SDT agrees that the issue you cite should not be covered in this standard. <b>The SDT will forward this comment on to the appropriate entity at NERC.</b></p>		
<p>PJM Interconnection, L.L.C.</p>	<p>Negative</p>	<p>PJM does not believe that the BA should be the entity responsible for the frequency response obligation, moreover the SDT has not sufficiently vetted the issue of applying the response requirements on an entity that cannot provide that service.</p> <p>PJM is concerned that the proposed draft does not explicitly cover the FERC Order 693 directives in the proposed requirements and rather addresses the directives indirectly in the attachments. This matter of mandatory vs. informational attachments must be formally clarified before approval can be given for this approach.</p> <p>PJM does not agree with the additional clarifying phrases being incorporated into the requirements. Explanatory phases should be included as text boxes as proposed in NERC’s Risk Based Methodology.</p>
<p><b>Response: The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</b></p> <p><b>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</b></p> <p><b>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</b></p> <p><b>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a</b></p>		

Organization	Yes or No	Question 10 Comment
<p>need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>Attachments that are referenced within a Requirement are mandatory and enforceable.</p> <p>The SDT has been instructed to include a “reliability outcome” within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.</p>		
Potomac Electric Power Co.	Negative	<p>The proposed standard is not reliability centered and will not improve reliability. 5) Potomac Electric Power Company supports the comments provided by PJM.</p>
<p>Response: The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>Attachments that are referenced within a Requirement are mandatory and enforceable.</p> <p>The SDT has been instructed to include a “reliability outcome” within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.</p>		
Atlantic City Electric Company	Negative	<p>See comments submitted by David Thorne in Segment 1, Potomac Electric Power Company</p>

Organization	Yes or No	Question 10 Comment
<p>Response: The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>Attachments that are referenced within a Requirement are mandatory and enforceable.</p> <p>The SDT has been instructed to include a “reliability outcome” within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.</p>		
Avista Corp.	Negative	<p>This standard should be designed for each interconnection explicitly rather than one size fits all. Frequency is an interconnection issue and response is driven by the interconnection's topology. One size does not fit all for interconnections. This standard should be designed around the explicit needs of each interconnection.</p> <p>Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.</p>
<p>Response: The SDT believes that an Interconnection has the capability to request a variance (especially one that is more restrictive), however the SDT has tried to prevent the need for variances by respecting the individuality of each of the Interconnections in</p>		

Organization	Yes or No	Question 10 Comment
		<p>setting Interconnection Frequency Excursion Threshold Values and Interconnection Frequency Response Obligations as noted in Attachment A and the Frequency Bias Setting Minimums in Attachment B.</p> <p>Early research by Nathan Cohn<sup>5</sup> on interconnected power system operations found that control is optimum if a BA’s Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased.</p> <p>The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in Attachment B. The attachment manages a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations.</p> <p>Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting to be 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.</p>
<p>Beaches Energy Services; City of Bartow, Florida; Tampa Electric Co.</p>	<p>Negative</p>	<p>We thank the SDT for their hard work and diligence in moving this Project forward. However, I have some concerns that cause me to not support the standard in its current form. In general, I believe that there has not been sufficient prudence review for the standard, especially R1, to justify a performance based standard around a Frequency Response Measure.</p> <p>I also believe that the proposed standard does not meet the intent of the Final SAR or Supplemental SAR. The “Final SAR” was to develop methods by which a performance based standard would eventually be developed. The Final SAR states: “The proposed standard’s intent is to collect data needed to accurately model existing Frequency Response. There is evidence of continuing decline in Frequency Response in the three Interconnections over the past 10 years, but no confirmed reason for the apparent decline. The proposed standard requires entities to provide data so that Frequency Response in each of the Interconnections can be modeled, and the reasons for the decline in Frequency Response can be identified. Once the</p>

<sup>5</sup> *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967



Organization	Yes or No	Question 10 Comment
		<p>reasons for the decline in Frequency Response are confirmed, requirements can be written to control Frequency Response to within defined reliability parameters.” BAL-003-1 is beyond the scope of this “Final SAR”. For instance, “the reasons for the decline in Frequency Response” were not confirmed to our knowledge; and the field trial is not completed to our knowledge. The Supplemental SAR adds to the scope of the Final SAR: “To provide a minimum Frequency Response Obligation for the Balancing Authority to achieve, methods to obtain Frequency Response and provide a consistent method for calculating the Frequency Bias Setting for a Balancing Authority. In addition, the standard will specify the optimal periodicity of Frequency Response surveys.” Please note that the Standards Development Roadmap does not confirm whether this Supplemental SAR was ever approved; hence, I question whether this is actually part of the scope of the SDT. Be that as it may, the Supplemental SAR does not eliminate the pre-requisite contained in the Final SAR to determine the reasons for the decline in frequency response and confirm them before establishing “defined reliability parameters”. In addition, the standard does not meet the scope requirements of the Supplemental SAR.</p>
<p><b>Response: The SDT is responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012.</b></p> <p><b>The SDT agrees that the original SAR was strictly for data collection. However, a supplemental SAR was developed to address the FERC March 18, 2010 Order and was subsequently approved by the industry.</b></p>		
<p>Constellation Energy Commodities Group</p>	<p>Negative</p>	<p>Please see submitted comments for additional detail behind the negative vote.</p>
<p><b>Response: Please see the SDT responses to your comments to the earlier questions.</b></p>		
<p>Energy Mark, Inc.</p>	<p>Negative</p>	<p>The issue of Median, Mean, Regression needs to be resolved using Field Trial data. This should be able to be completed before the end of January 2012.</p>

Organization	Yes or No	Question 10 Comment
		<p>The FRO and Minimum Bias Setting allocations should be determined using a single allocation method and a single data set.</p> <p>Wording changes are needed in the Requirements to indicate compliance in all cases for all BAs.</p> <p>In general, although this standard has many weaknesses, its implementation with small modifications will be better than failure to implement it.</p>
<p><b>Response: The drafting team is recommending use of the median for the purposes of determining a BA FRM over multiple events. This decision is based on the determination that, while it may not be perfect, it is better than the other alternatives available at this time. The drafting team recognizes that in the future a better methodology might be found; based on the data available at this time the median allows us to move forward to implement a response requirement.</b></p> <p><b>The drafting team understands your concern of using the historical numbers for the FRO allocation and the projected number as the basis for the minimum Frequency Bias Setting. However, after discussions, the drafting team believes that at this time, minimizing the changes to the current Frequency Bias Setting process provides better comparability for the purpose of evaluating the impacts of reducing the minimum setting requirement. In the alternative, the drafting team feels that allocating the FRM based on historical data provides less room to game the process since the numbers used for allocation can be verified independently.</b></p> <p><b>The SDT has modified the requirements and believes that your concern has now been addressed.</b></p> <p><b>The SDT thanks you for your comment.</b></p>		
Energy Mark, Inc.	Negative	<p>The Time Horizon for R1 is Operations Assesment. It should be Real Time. Frequency Response is a service that is automatic. It does not require operator action to activate the service. It requires that the operator set-up the system to provide the automatic response before an event requiring Frequency Response occurs. Unlike other Real Time services, if the operator fails to set-up the system to provide this service before Real Time, there is no action that the operator can take to provide the service in response to an event. Many other actions in the standards required by the system operator are considered to be Real Time because the operator can take action after an event occurs. It does not make sense to consider an action that must</p>

Organization	Yes or No	Question 10 Comment
		be taken before Real Time as Operations Assessment.
<p><b>Response:</b> The requirement does not fall into a single category<sup>[MEL40]</sup>. The operator is constantly taking actions some of which were set in a “longer term” horizon, some in a “real-time” horizon and this is an after-the-fact measure.</p>		
Fort Pierce Utilities Authority	Negative	FPUA supports the comments submitted by Florida Municipal Power Agency (FMPA) through the formal comment process.
<p><b>Response:</b> Please refer to the SDT response to the comments received from FMPA in the earlier questions.</p>		
Hydro One Networks, Inc.	Negative	<p>Hydro One is casting a negative vote for this project. We support and subscribe to the comments submitted by NPCC on behalf of its members.</p> <p>In summary, the comments are:</p> <ul style="list-style-type: none"> <li>1 o Use of 59.6 Hz as an Eastern Interconnection UFLS instead of an actual value of either 59.5 Hz or 59.7 Hz.</li> <li>2 o Use of installed capacity in determining the Frequency Response Obligation.</li> <li>3 o The sampling interval should be tuned on a per Interconnection basis to support HQTE’s characteristics.</li> <li>4 o NPCC does not advocate the use of supplemental regulation as a method of procuring frequency response.</li> <li>5 o BAL-003-1 is applicable only to Balancing Authorities and Reserve Sharing Groups. A common concern that has been expressed in the industry is that the burden of compliance is being placed solely on Balancing Authorities while the main sources of discretionary frequency response are generators.</li> <li>6 o Balancing Authorities must be able to provide sufficient frequency response and be able to and the proper frequency bias settings applied in their AGC systems are necessary.</li> <li>7 o In the formula for determining the Balancing Authority’s FRO allocation, installed</li> </ul>

Organization	Yes or No	Question 10 Comment
		<p>capacity is used. Is there a clear and consistent definition for installed capacity? Considering the growth of wind energy development, the delivered energy from wind generation over longer time horizons will be substantially less than the machine nameplate ratings.</p> <p>8 o The background document refers to the use of peak generation instead of installed capacity. Which shall be used?</p> <p>o Additional minor issues for the SDT consideration that should be addressed:</p> <p style="padding-left: 40px;">? A link should be provided in the standard to FRS Form 1, or instructions provided for how entities may find the form.</p> <p style="padding-left: 40px;">? In the definitions, FRS should be spelled out before using the acronym.</p>
<p><b>Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for its higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the Eastern Interconnection to continuously carry about 4,000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.</b></p> <p><b>2, 7 &amp; 8 – The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses “historical data” to circumvent the problem you have described.</b></p> <p><b>3 – The SDT adjusted the event selection Criteria to address concerns related to response driving frequency back to the pre-event level during the B value measurement period. We believe that this adjustment addresses your concern.</b></p> <p><b>4 – The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.</b></p> <p><b>The drafting team believes the following are valid methods of obtaining Frequency Response:</b></p> <ul style="list-style-type: none"> <li>• Regulation services.</li> <li>• Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from</li> </ul>		

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		<p>Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.</p> <ul style="list-style-type: none"> <li>• Through a tariff (e.g. Frequency Response and regulation service).</li> <li>• From generators through an interconnection agreement.</li> <li>• Contract with an internal resource or Loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).</li> </ul> <p>Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.</p> <p>5 – The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>6 – The SDT agrees with you comment.</p> <p>Additional minor issues</p> <p>The Forms will be put on a NERC website and announced once the standard is approved.</p>

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<p>The definition no longer reference FRS Form 1.</p>		
<p>Independent Electricity System Operator</p>	<p>Negative</p>	<p>The complete IESO’s comments on the revised standard are provided through the electronic comment form. The summary below highlights IESO's major concerns with the revised standard:</p> <p>1)The definition for Frequency Response Measure (FRM): The proposed FRM definition: “The median of all the Frequency Response observations reported annually on FRS Form 1” is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an attachment to the standard. In the current NERC Glossary of Terms, there is no such precedence that a definition must rely on the requirements or details in a standard for completeness. Also, it is very cumbersome that when changes are made to FRS Form 1, the definition must be posted for industry comment and balloting, and vice versa. When other standards begin using the term, there will be cross references between standards. This further complicates the update/maintenance problem without any appreciable value. (See complete comment in Section Q1 in the electronic comment form)</p> <p>2)Attachment A: Attachment A should include only the event selection process and calculations associated with the requirements, including an explanation of what is necessary if variable Frequency Bias Settings are implemented. If other "requirements" need to be specified, such as the reporting time frame stipulated on page 3 of Attachment A, they should be moved to the standard itself but not imbedded in an attachment. (See complete comment in Section Q6 in the electronic comment form)</p> <p>3)The expanded FRS Form 1 and the addition of a Form 2 ask for data entry that is excessive and whose value has not been demonstrated. (See complete comment in Section Q9 in the electronic comment form)</p>
<p><b>Response: 1) The SDT has modified the definition to no longer reference FRS Form 1. The definition now reads “The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This</b></p>		

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		<p>will be calculated as MW/0.1Hz.”</p> <p>2) The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on its FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that indicated requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it cannot be changed without input from the industry.</p> <p>3) The SDT points out that there are no additional data requirements. It is possible that you are seeing more spreadsheets due to them being unhidden.</p> <p>Form 2 is a separate stand-alone workbook. Form 1 does have a worksheet labeled “BA Form 2 Event Data” that will contain the single event data from each of the BA’s Form 2s. Two additional worksheets were added to Form 1 and several worksheets were deleted. The “Time Zone Ref” worksheet was added to allow the BA to enter the time zone of its data and have the spreadsheet calculate the local time of the event from the UTC time. This was added for the convenience of the BA in collecting the correct data for each event and does not require additional data from the BA. The second worksheet added was a worksheet that displays graphs of frequency for each event and the t(0) selected correctly. This was added to aid the BA with data collection and the selection of t(0) since this seemed to be one of the biggest problems during the first phase of the field trial. This graph worksheet does not require the BA to do anything. It is not used in the analysis and can be deleted. Deleting this worksheet will greatly reduce the size of Form 1. None of the data requirements on Form 1 or Form 2 have changed from previous versions. The absolute minimum data needed for this standard is the date/time, frequency and NAI in columns A, B and C of the “Data” worksheet in Form 2. Columns D through I have been totally optional and can be left blank. Column J is the Bias setting in the ACE equation and is important to BA’s that utilize Variable Bias. Column K, BA Load, was added by the drafting team in the beginning to see if Load Dampening could be measured as this has been done for several years on one Interconnection. Column I of the “Data” worksheet is the only optional data that the BA should use when it is the contingent BA during any of the events evaluated. Utilizing this data will allow the BA’s SEFRD to be calculated correctly and give the BA a full sample set for the annual median calculation. Form 2 is necessary to standardize the measurement process on all Interconnections. You are free to hide any analytical worksheets on Form 1 and Form 2. You can do this on your “master” Form 2 and then build each Form 2 for each event using this master. These additional worksheets are available for BAs to utilize if they find that their performance is below the FRO and will aid the analysis of the contributing causes.</p>

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ISO New England, Inc.	Negative	<p>ISO New England will not vote to approve the standard because it fails to place requirements on generators to provide frequency response. There are four substantive problems:</p> <ul style="list-style-type: none"> <li>1 • Using 59.6 Hz as an Eastern Interconnection UFLS instead of an actual value of either 59.5 Hz or 59.7 Hz</li> <li>2 • Using installed capacity in determining the Frequency Response Obligation</li> <li>3 • The sampling interval needs to be tuned on a per Interconnection basis to support HQTE’s characteristics</li> <li>4 • Do not advocate the use of supplemental regulation as a method of procuring frequency response</li> </ul> <p>Additionally, the SDT must decide on what the purpose of this standard is. If it is to respond to Order 693 then the standard misses the point of defining how often to run Frequency Response Surveys; it does not crisply define the “Interconnection” obligations. If the SDT does want to focus on performance then the issue of who is the default provider must be addressed. As the IRC has noted previously, all BAs do not own the service providers. To create standards that apply to entities that are dependent on other function entities to comply with a standard requirement is of great concern.</p>
<p><b>Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the East to continuously carry about 4000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.</b></p> <p><b>2 – The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses “historical</b></p>		



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		<p>data” to circumvent the problem you have described.</p> <p>3 – The SDT adjusted the event selection Criteria to address concerns related to response driving frequency back to the pre-event level during the B value measurement period. We believe that this adjustment addresses your concern.</p> <p>4 – The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.</p> <p>The drafting team believes the following are valid methods of obtaining Frequency Response:</p> <ul style="list-style-type: none"> <li>• Regulation services.</li> <li>• Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.</li> <li>• Through a tariff (e.g. Frequency Response and regulation service).</li> <li>• From generators through an interconnection agreement.</li> <li>• Contract with an internal resource or Loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).</li> </ul> <p>Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.</p> <p>The NERC <u>Functional Model Technical Document</u> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency</p>

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<p>response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>6 – The SDT agrees with you comment.</p> <p>Additional minor issues</p> <p>The Forms will be put on a NERC website and announced once the standard is approved.</p> <p>The definition no longer reference FRS Form 1.</p>		
JEA	Negative	<p>JEA is not comfortable with a performance based standard as written without more field testing to ensure that net interchange is not skewed by load and generation changes that are not a function of frequency. Since frequency response has components from load and generation resources, and load is not controllable for the most part, seems this standard should be directed at specific generator response methods from the GO/GOP's.</p> <p>This is a wide reaching standard. And, this is a performance standard (if it doesn't perform as designed, it is a violation). Because of this, more testing needs to be completed so we know the model is correct. We are not sure we know how to ensure compliance.</p> <p>Don't agree the standard needs to be performance based.</p>
<p>Response: Based on the studies performed by the SDT, the drafting team believes that a calculation of the median of multiple events addresses the concerns raised by the noise being inside a single event. The studies from the field trial show a convergence of the measurement after approximately 20 to 25 events.</p> <p>The SDT is responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012.</p>		

Organization	Yes or No	Question 10 Comment
Kansas City Power & Light Co.	Negative	The proposed Standard BAL-003-1 does not consider the real time operating conditions under which this standard should apply. There are no considerations for the complexities introduced by capacity energy agreements between BA's nor consideration of the differing level of Interconnection Frequency Response needed at times of minimum interconnection load conditions and interconnection peak load conditions.
<p><b>Response: The method for determining the FRO is based upon the determination of the largest contingency that could occur at any time and does not vary based upon time of day or system conditions. Since the largest contingency could occur at any time, the minimum Frequency Response Obligation necessary to manage the contingency will not be dependent upon the differing conditions that can occur during different times of the day like those referred to in the question.</b></p>		
Lakeland Electric	Negative	In general; here has not been sufficient prudence review for the standard, especially R1, to justify a performance based standard around a Frequency Response Measure. Refer to comments submitted by FMPA on LAK behalf.
<p><b>Response: The SDT is responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012.</b></p> <p><b>Please refer to the SDT response to the comments received from FMPA in the earlier questions.</b></p>		
Liberty Electric Power LLC	Negative	Voting no due to SDT addressing FERC directives with attachments instead of in the standard requirements.
<p><b>Response: The SDT disagrees with your concern about addressing FERC directives within an attachment. If a requirement references specific performance in an Attachment, then the performance described in the Attachment is mandatory and enforceable.</b></p>		
Manitoba Hydro	Negative	The Applicability of BAL-003-1 should be clarified. Specifically, Section 1.2 should be changed from "Reserve Sharing Groups (where applicable)" to "Reserve Sharing Group

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		<p>whose intent includes meeting Frequency Response Obligations”.</p> <p>Regarding Data Retention:</p> <ol style="list-style-type: none"> <li>1. As the standard is currently drafted, both the BA and the RSG would be required to retain data or evidence to show compliance with requirements R1 and M1. It is unclear whether this is the intention, or whether it would be acceptable that just one or the other would maintain such records.</li> <li>2. In the first and second paragraph, the reference to ‘three calendar years’ should be specified to be the ‘previous three calendar years’.</li> <li>3. In the third paragraph, it should be clarified who is required to keep information related to non compliance if the BA belongs to an RSG – the BA or the RSG or both.</li> <li>4. In the fourth paragraph, it should be clarified for what length of time the last audit records must be retained.</li> </ol>
<p><b>Response:</b> The SDT has defined a new term “<b>Frequency Response Sharing Group (FRSG)</b>” because it believes that using the presently defined term “<b>Reserve Sharing Group</b>” could cause confusion. The new definition reads “<b>A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.</b>” The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.</p> <p><b>1 &amp; 3 - The SDT believes that the reporting entity would be the responsible entity to maintain records. The SDT also believes that once a BA has declared themselves as part of a FRSG then the FRSG would be the responsible entity to maintain records.</b></p> <p><b>2 - The SDT agrees with your second comment and has made this modification.</b></p> <p><b>4 – The last audit record should be kept until the next audit.</b></p>		
New Brunswick Power Transmission Corporation	Negative	<p>The compliance burden should not fall on the BA as the provider of Frequency Response (i.e. Primary Control response). In this case the BA per se has no assets, moreover the primary response service providers have no obligations to provide the service, thus the BA potentially could face a situation where there is no physical service to be purchased but there is a mandated standard to comply with. The idea</p>

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		of creating a Primary Response Market as some have proposed does not work without an obligation on some entity to physically provide that service.
<p><b>Response:</b> The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p>		
New York State Department of Public Service, National Association of Regulatory Utility Commissioners	Negative	After review of the standard and draft comments to be submitted by industry participants, it appears that there are many areas of the proposed standard that require clarification.
<p><b>Response:</b> The SDT thanks you for your participation. Please be more specific about what needs clarification so the SDT can address your specific concerns.</p>		
Northeast Power Coordinating Council	Negative	<p>This standard as written does not place requirements on generators to provide frequency response. There are four substantive problems:</p> <p>1 • Using 59.6 Hz as an Eastern Interconnection UFLS instead of an actual value of either 59.5 Hz or 59.7 Hz.</p>

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		<p>2 • Using installed capacity in determining the Frequency Response Obligation.</p> <p>3 • The sampling interval needs to be tuned on a per Interconnection basis to support HQTE’s characteristics.</p> <p>4 • Do not advocate the use of supplemental regulation as a method of procuring frequency response.</p> <p>It must be decided as to what the purpose of this standard is. If it is to respond to Order 693 then the standard misses the target of defining how often to run Frequency Response Surveys; it does not crisply define the “Interconnection” obligations. If performance is the focus, then the issue of who is the default provider must be addressed. All BAs do not own the service providers. To create standards that apply to entities that are dependent on other functional entities to comply with a standard requirement is of great concern.</p> <p>FRS Form 1 is listed as being an Associated Document. Will it be attached to the standard?</p> <p>The acronym FRS is used in the standard. FRS should be spelled out before its acronym is used.</p> <p>If FRS Form 1 will not be an appendix or an attachment to the document, then a link should be provided to it, or instructions given on how to find it.</p>
<p><b>Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the Eastern Interconnection to continuously carry about 4000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.</b></p> <p><b>2 – The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses “historical</b></p>		

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		<p>data” to circumvent the problem you have described.</p> <p>3 – The SDT adjusted the event selection Criteria to address concerns related to response driving frequency back to the pre-event level during the B value measurement period. We believe that this adjustment addresses your concern.</p> <p>4 – The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.</p> <p>The drafting team believes the following are valid methods of obtaining Frequency Response:</p> <ul style="list-style-type: none"> <li>• Regulation services.</li> <li>• Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.</li> <li>• Through a tariff (e.g. Frequency Response and regulation service).</li> <li>• From generators through an interconnection agreement.</li> <li>• Contract with an internal resource or Loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).</li> </ul> <p>Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.</p> <p>The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency</p>

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<p>New Brunswick System Operator</p>	<p>Negative</p>	<p>Please see comments submitted by the NPCC Reliability Standards Committee and the IRC Standards Review Committee</p>
<p>Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the East to continuously carry about 4,000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.</p> <p>2 – The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses “historical data” to circumvent the problem you have described.</p> <p>3 – The SDT adjusted the event selection Criteria to address concerns related to response driving frequency back to the pre-event level during the B value measurement period. We believe that this adjustment addresses your concern.</p> <p>4 – The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.</p> <p>The drafting team believes the following are valid methods of obtaining Frequency Response:</p> <ul style="list-style-type: none"> <li>• Regulation services.</li> <li>• Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined,</li> </ul>		



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New York Independent	Negative	The NYISO's comments are included with both the Joint IRC/SRC and Joint NPCC RSC

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System Operator		comments.
<p>Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the Eastern Interconnection to continuously carry about 4,000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.</p> <p>2 – The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses “historical data” to circumvent the problem you have described.</p> <p>3 – The SDT adjusted the event selection Criteria to address concerns related to response driving frequency back to the pre-event level during the B value measurement period. We believe that this adjustment addresses your concern.</p> <p>4 – The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.</p> <p>The drafting team believes the following are valid methods of obtaining Frequency Response:</p> <ul style="list-style-type: none"> <li>• Regulation services.</li> <li>• Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.</li> <li>• Through a tariff (e.g. Frequency Response and regulation service).</li> <li>• From generators through an interconnection agreement.</li> <li>• Contract with an internal resource or Loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).</li> </ul> <p>Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.</p>		

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		<p>The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p> <p>FRS Forms 1 and 2 will be Attached to the standard. The Forms will be put on a NERC website and announced once the standard is approved.</p> <p>The definition no longer reference FRS Form 1.</p>
Rochester Gas and Electric Corp.	Negative	RG&E supports comments to be submitted to NPCC.
		<p>Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the East to continuously carry about 4,000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.</p> <p>2 – The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses “historical</p>

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Orlando Utilities Commission	Negative	Per LPPC comments
<p><b>Response: The SDT is not sure of the entity you are referencing (LPPC). Therefore, the SDT cannot respond to your comment without further clarification.</b></p>		
Portland General Electric Co.	Negative	PGE agrees with the WECC whitepaper including the comments and concerns.
<p><b>Response: see WECC comments.</b></p>		
PPL Electric Utilities Corp.; PPL Generation LLC	Negative	<p>The PPL Companies do not support proposed Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) primarily because PPL believes it inappropriately subjects Reserve Sharing Groups (RSGs) to the proposed requirements. The proposed Applicability provision states that the mandatory reliability requirements would be applicable to (1) Balancing Authorities and (2) Reserve Sharing Groups (where applicable). However, it is unclear how the proposed requirements would be applicable to an RSG. RSGs typically do not provide a mechanism for sharing automatic Frequency Response. The BA Frequency Response Obligation (FRO) is a formula based on BAs and the Interconnection and has nothing to do with RSGs. Rather, RSGs collectively respond to requests for activation of contingency reserves generally after the request is made by a member Balancing Authority. The Standard Drafting Team should therefore remove RSGs from the Applicability section and should remove all other references to RSGs in the proposed</p>

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		standard.
<p>Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p>		
PPL EnergyPlus LLC	Negative	Please refer to PPL's corporate comments.
<p>Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”</p>		
Seattle City Light	Negative	<p>LADWP and SCL support project 2007-12’s general approach to frequency response, and is prepared to support the ballot once several problematic details are corrected.</p> <p>o LADWP and SCL note that the time allowed to analyze the final “official” set of 25 events for each year, from Dec 15 to Jan 10, is relatively short and coincides with the holiday vacation season</p>
<p>Response: The ERO will be posting preliminary events throughout the year. The criteria contained in Attachment A should allow an entity to evaluate events as they occur. This coupled with the Forms 1 &amp; 2 should allow an entity to be looking forward throughout the year. In addition the standard allows 30-days for providing information.</p>		
Seattle City Light	Negative	<p>SCL would like to see addressed in the Standard how the case is to be addressed where a BA simply has no frequency response information to provide, as could happen for a small 1-2 generator BA which has its generators out of service for an extended period for maintenance or upgrades. Assuming the BA purchases frequency response services from another entity during this period, is the BA out of</p>

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		<p>compliance with the proposed Standard simply because it has no data report? And how is its next-year obligation to be computed? These issues should be addressed in the Measures or Additional Compliance information. If these are issues for “lawyers” as the Standards Drafting Team indicated during the November 14, 2011, webinar then the team should engage a NERC lawyer to resolve them prior to releasing the Standard for ballot.</p> <p>o Finally, SCL points out that the proposed Standard introduces a new obligation on applicable entities to maintain frequency responsive reserves. Although this obligation does not appear to be unreasonable or problematic in general, compliance may prove difficult for some entities and in some localized areas.</p>
<p><b>Response: The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.</b></p> <p><b>The drafting team believes the following are valid methods of obtaining Frequency Response:</b></p> <ul style="list-style-type: none"> <li>• Regulation services.</li> <li>• Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.</li> <li>• Through a tariff (e.g. Frequency Response and regulation service).</li> <li>• From generators through an interconnection agreement.</li> <li>• Contract with an internal resource or loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).</li> </ul> <p>Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.</p>		
Public Utility District No. 1 of Snohomish	Negative	Public Utility District No. 1 of Snohomish County supports the comments filed by

Organization	Yes or No	Question 10 Comment
County/Snohomish County PUD No. 1		Seattle City Light.
<p>Response: The ERO will be posting preliminary events throughout the year. The criteria contained in attachment A should allow an entity to evaluate events as they occur. This coupled with the Forms 1 &amp; 2 should allow an entity to be looking forward throughout the year. In addition the standard allows 30-days for providing information.</p> <p>The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.</p> <p>The drafting team believes the following are valid methods of obtaining Frequency Response:</p> <ul style="list-style-type: none"> <li>• Regulation services.</li> <li>• Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.</li> <li>• Through a tariff (e.g. Frequency Response and regulation service).</li> <li>• From generators through an interconnection agreement.</li> <li>• Contract with an internal resource or Loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).</li> </ul> <p>Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.</p>		
South California Edison Company	Negative	<p>SCE's "No" vote, like the WECC position, regarding Project 2007-12 is based on the following five points:</p> <ol style="list-style-type: none"> <li>1) Clarification is needed whether there will/ will not be conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction</li> <li>2) Confusion exists between Attachment A and the Background Document:</li> </ol>



Organization	Yes or No	Question 10 Comment
		<p>2a) Attachment A states peak load allocation is based on “Projected” Peak Loads and Generation, versus</p> <p>2b) The Background Document which states it will use “historical” Peak Load and Generation.</p> <p>3) Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.</p> <p>4) There is no clear statement of what is expected from the Balancing Authorities and whether or not there is a limit on that expectation.</p> <p>5) Why are there no requirements on governor installation, settings, and operation for a frequency response standard?</p>
<p><b>Response: 1) The SDT has removed Requirement R3. The SDT believes that this requirement is duplicative of BAL-005-0.1b Requirements R6 &amp; R7.</b></p> <p><b>2) The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses “historical data” to circumvent the problem you have described.</b></p> <p><b>3) Early research by Nathan Cohn<sup>6</sup> on interconnected power system operations found that control is optimum if a BA’s Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased.</b></p> <p><b>The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in Attachment B. The attachment manages a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations.</b></p> <p><b>Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting</b></p>		

<sup>6</sup> *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

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		<p>to be 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. <b>The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.</b></p> <p>4) The SDT understands your concern and has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide</p> <p>5) The NERC <i>Functional Model Technical Document</i> identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.</p> <p>The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.</p> <p>There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.</p> <p>Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.</p>
Western Area Power Administration	Negative	<ol style="list-style-type: none"> <li>1. Reducing frequency bias obligation is a detriment to reliability of interconnection and the proposed standard aims to reduce the bias obligation from the current minimum level of 1% load to 0.8% and subsequently to a lower percentage.</li> <li>2. The proposed standard is very confusing and complex in regard to data collection and compliance.</li> <li>3. The proposed standard is encompassing reserve sharing group (where applicable), why? What reserve sharing group operates AGC?</li> </ol> <p>It is not clear whether the compliance period is monthly or yearly for R1 &amp; R5.</p> <p>The issue of non-binding standard and whether it serves a purpose to go through</p>

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		<p>complicated data submission and found in compliance or out of compliance without any consequences.</p>
<p>Response: 1. Early research by Nathan Cohn<sup>7</sup> on interconnected power system operations found that control is optimum if a BA’s Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased.</p> <p>The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in Attachment B. The attachment manages a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations.</p> <p>Based on concerns raised by the Industry, the drafting team has modified Attachment B to make the initial minimum Bias Setting to be 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.</p> <p>3. The SDT has modified the Background Document to provide additional information and clarity.</p> <p>4. The SDT modified R1 so that it no longer applies to an RSG _ the SDT defined new term, “Frequency Response Sharing Group” to address stakeholder concerns that the RSG is not the correct entity. The definition of Frequency Response Sharing Group is:</p> <p>A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.</p> <p>3. Requirement R1 is calculated on an annual basis. The SDT has removed Requirement R5 and combined it into Requirement R2 and new Requirement R3.</p> <p>The SDT made modifications to Attachment A to try to distinguish mandatory performance assigned to the BA from process steps performed by the ERO.</p>		
Xcel Energy, Inc.	Negative	<p>It is not clear if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of FR expected on a total basis. Balancing</p>

<sup>7</sup> *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

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		<p>Authorities need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet this requirement. The documents do not appear to provide any boundary on the maximum amount of FR that a BA will provide, i.e. it is not clear what will happen if an event occurs in the Eastern Interconnection that causes the frequency to drop to less than 59.6 Hz (e.g. what if freq dips to 59.0? Is the BA expected to provide a limitless amount of frequency response?). Also, is that event excluded from the list used to calculate the Balancing Authorities' response or is it included with an expectation that it counts the same as any other event. Without a clear statement of what is expected, including whether there is a limit on that expectation or not, the Balancing Authorities cannot know what is expected of them and therefore cannot plan appropriately.</p>
<p><b>Response: The SDT understands your concern and has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.</b></p>		
	<p>Negative</p>	<p>59.6 Hz should be used as the Eastern Interconnection URLS.</p> <p>Installed capacity should always be used determining an area's frequency response obligation.</p> <p>I question the use of supplemental regulation as a method of procuring frequency response. Is this an acceptable practice throughout all NERC Regions?</p> <p>Each Balancing Authority must be able to provide the required or calculated frequency response and be able to incorporate the proper frequency bias settings in the Balancing Authority's AGC system.</p> <p>A link should be provided in the proposed standard to FRS Form 1.</p>
<p><b>Response: Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the East to continuously carry about 4,000 MW of frequency</b></p>		

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END OF REPORT