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 standards were 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.

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

http://www.nerc.com/filez/standards/Frequency_Response.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Murphey	BPA	WECC	1
2.	Bart McManus	BPA	WECC	1
3.	David Kirsch	BPA	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tino Zaragoza	IID	WECC	1
2.	Jesus Sammy Alcaraz	IID	WECC	3
3.	Diana Torres	IID	WECC	4
4.	Marcela Caballero	IID	WECC	5

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

5. Cathy Bretz	IID	WECC	6

				1	2	3	4	5	6	7	8	9	10
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

				1	2	3	4	5	6	7	8	9	10
4.	Group	Will Smith	MRO NSRF										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1

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

3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	NSP (XCEL)	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	1, 3, 5, 6
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	RICHARD BURT	MPC	MRO	1, 3, 5, 6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Andy Burch	EEI	SERC	5
2.	Bob Dalrymple	TVA	SERC	1, 3, 5, 6
3.	Brad Gordon	PJM	SERC	2
4.	Vicky Budreau	SCPSA	SERC	1, 3, 5, 6
5.	Sam Holeman	Duke	SERC	6, 1, 3, 5
6.	Cindy Martin	Southern Co	SERC	1, 5
7.	Scott Brame	NCEMC	SERC	1, 3, 4, 5
8.	Wayne Van Liere	LGE-KU	SERC	3
9.	Larry Akens	TVA	SERC	1, 3, 5, 6
10.	John Troha	SERC Reliability Corp.	SERC	10

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 3, 5
2.	David Dockery	Assocoated Electric Cooperative	SERC	1, 3, 5

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

3.	Lisa Duffey	Cleco Power	SPP	1, 3, 5
4.	Jonathan Hayes	SPP	SPP	2
5.	Steve Haun	Lincoln Electric System	MRO	1, 3, 5
6.	Tony McMurtry	Lafayette Utilities System	SPP	NA
7.	Dave Milliam	Kansas City Power & Light	SPP	1, 3, 5, 6
8.	Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
9.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Steve Rueckert	Western Electricity Coordinating Council										X

No additional members listed.

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X	X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Thomas McElhinney	JEA Electric Compliance	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Babik	JEA Electric Compliance	FRCC	5
2.	Ted Hobson	JEA Electric Compliance	FRCC	1
3.	Garry Baker	JEA System Operations	FRCC	3

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Al DiCaprio	ISO/RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Yeung	SPP	SPP	2
2.	Kathleen Goodman	ISO-NE	NPCC	2
3.	Gary DeShazo	CAISO	WECC	2
4.	Greg Campoli	NYISO	NPCC	2
5.	Steve Myers	ERCOT	ERCOT	2

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

6. Don Weaver	NBSO	NPCC	2
7. Mark Thompson	AESO	WECC	2
8. Ben Li	IESO	NPCC	2

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Jason L. Marshall	ACES Power Marketing Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 5, 6
2. James Jones	Arizona Electric Power Cooperative/Southwest Transmission Cooperative	WECC	1, 5, 6
3. Erin Woods	East Kentucky Power Cooperative	SERC	1, 3, 5, 6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Joe Tarantino	Sacramento Municipal Utility District (SMUD)	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Kevin Smith	Balancing Authority of Northern California (BANC)	WECC	1

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Individual	Emily Pennel	Southwest Power Pool Regional Entity										X
14.	Individual	Cindy Oder	Salt River Project	X		X		X	X				
15.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
16.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
17.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
18.	Individual	Howard F. Illian	Energy Mark, Inc.								X		
19.	Individual	Don McInnis	Florida Power & Light Company	X		X		X					
20.	Individual	Carlos J. Macias	FPL	X		X		X	X				
21.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
22.	Individual	Thomas Washburn	FMPP						X				
23.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
24.	Individual	Kathleen Goodman	ISO New England Inc		X								
25.	Individual	John Tolo	Tucson Electric Power	X									

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

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

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Seattle City Light	Negative	Answer: No. Comments: LADWP and SCL recommend the following change to the definition of Frequency Bias Setting. LADWP believes that this change increases the clarity of the definition: Original A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems. Proposed Change A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's Frequency Response contribution to the Interconnection, and prevent response withdrawal through secondary control systems
Response:		
Alliant Energy Corp. Services, Inc.	Negative	The definition of Frequency Bias Setting should focus on what it is. balancing Authorities do not supply energy. seggest rivising it to "A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to approximate the expected natural response provided by the assets within the respective Balancing Authority's area."

Organization	Yes or No	Question 1 Comment
Response:		
Potomac Electric Power Co.	Negative	The proposed new Definitions do not stand alone and are also linked to Attachments.
Response: term when used in att the term has the sazme meaning as defined		
ISO/RTO Council Standards Review Committee	No	(1) In our previous comments, we suggested to drop the definitions for the terms FRM and FRO in favor of providing the needed wording in the standard itself to take care of the specific details. The SDT did not adopt our suggestion with the reason that these definitions will be used by other standards in the future. That's fair enough. However, the FRM definition: "The median of all the Frequency Response observations reported annually on FRS Form 1" is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an Attachment to a standard. In the current NERC Glossary of Terms, there is no such precedence that a definition must rely on the requirements or details in a standard for completeness. Also, it is very cumbersome that when changes are made to FRS Form 1, the definition must be posted for industry comment and balloting, and vice versa. When other standards begin using the term, there will be cross references between standards. This further complicates the update/approval process without any appreciable value.Once again, we strongly urge the SDT to consider dropping these definitions, and have the details fully specified in the standard body itself. This will eliminate that cross reference issue. After all, the definition for FRM is a simple sentence and does not provide any clarity or specific details that cannot be presented by using appropriate wording in a requirement. (2) The definition of Frequency Bias Setting, if retained, should focus on what it is. Balancing Authorities do not supply energy. We suggest to

Organization	Yes or No	Question 1 Comment
		revise it to:Frequency Bias Setting A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's (BA's) Area Control Error (ACE) equation to approximate the expected natural response provided by the assets within the respective Balancing Authority's area.
Response: review need for FRM & FRO in Glossary		
Duke Energy	No	Duke Energy would suggest removing "usually" from the Frequency Bias Setting definition, as the value in the ACE equation must be in terms of MW/0.1Hz in order for ACE to be correctly calculated. We apologize for missing this point in the last round of comments. Though some would argue that the last phrase of the definition is more of an explanation of a function rather than a definition, we support keeping the phrase inserted, as it should be recognized that the intent is to account for the frequency response contribution AND keep the FBS slightly larger (in magnitude) than the average estimated response, to better discourage withdrawal, which was also recognized by Nathan Cohn. Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?
Response:		
Independent Electricity System Operator	No	In our previous comments, we suggested to drop the definitions for the terms FRM and FRO in favor of providing the needed wording in the standard itself to take care of the specific details. The SDT did not adopt our suggestion with the reason that these definitions will be used by other standards in the future. That's fair enough. However, the FRM definition: "The median of all the Frequency Response observations reported annually on FRS Form 1" is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an attachment to a standard. In

Organization	Yes or No	Question 1 Comment
		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.Once again, we strongly urge the SDT to consider dropping these definitions, and have the details fully specified in the standard body. This will eliminate the cross reference issues. After all, the definition for FRM is a simple sentence and does not provide any clarity or specific details that cannot be addressed by providing the appropriate wording in a requirement.With this cross-reference issue, combined with the issues associated with Attachments A and B (see our comments under Q6, below), we are unable to support this standard at this time.
Response: ISO\RTO response		
Keen Resources Asia Ltd.	No	In the Standard, the definition of Frequency Response Measure (FRM) is statistically wrong. The median is an improper statistical measure of Frequency Response because--it truncates large excursions which are the specific subject of Frequency Response control, not normal operating frequency errors which are self-correcting and are the subject of CPM control;--it is non-linear; and therefore--it is non-summable over the interconnection; in other words, the individual BA medians don't add up to the interconnection median, in complete incompatibility with CPM control which requires summability of BA performances into the interconnection's performance. Moreover, it is mathematically impossible to sum the medians of the BAs in a Reserve Sharing Group (RSG) into the RSG's median: 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

Organization	Yes or No	Question 1 Comment
		is patently wrong, invented, and supported in no probability & statistics literature whatsoever. As a practicing statistician, I hereby give testimony to the utter falsehood of the statement that "In general, statisticians use the median as the best measure of central tendency when a population has outliers." (See http://www.robertblohm.com/BestStatistic.doc for an explanation of "best statistic" which is a highly technical and central topic in modern probability theory and statistics.) Also, "outliers" are falsely and rhetorically claimed to be "noise" when in fact they are the "events" that are the specific subject of Frequency Response. It is well known that they do not "fit" a normal distribution. They are distinct from the normal operating errors that are the subject of CPM control. The paragraph does correctly conclude that the linear regression more accurately incorporates outliers than the median does, although the paragraph uses rhetoric by calling this improvement "skew" as if it is distortionary when, in fact, the median distorts the reality.
Response: some of issues raised are tangential & median is appropriate for these reasons		
Manitoba Hydro	No	It is not clear why the term “Single Event Frequency Response Data (SEFRD)” has been removed from the standard but is still used and defined in the Background Document and Attachment A.
Response: only used in calculation process – does not need to be defined		
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

Organization	Yes or No	Question 1 Comment
		or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to account for the Balancing Authority’s Frequency Response contribution to the Interconnection, and discourage prevent response withdrawal through secondary control systems
Response: need to remove duplicate		
Los Angeles Department of Water and Power	No	LADWP recommends the following change to the definition of Frequency Bias Setting (replace the word "discourage" with the word "prevent"). LADWP believes that this change increases the clarity of the definition:OriginalA number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to account for the Balancing Authority’s Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.Proposed ChangeA number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to account for the Balancing Authority’s Frequency Response contribution to the Interconnection, and prevent response withdrawal through secondary control systems
Response: seattle city response		
Progress Energy	No	PGN supports the collective comments of SERC members.We feel that the last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. While the SERC OC Standards Review Group understands the statement, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word “Interconnection”. Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?

Organization	Yes or No	Question 1 Comment
Response:		
ERCOT	No	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.A BA that does not own generation resources cannot provide Frequency Response, it can only schedule and dispatch available resources capable of such; . The BA should be responsible for taking action to schedule resources that are capable of frequency response, and monitoring to assure frequency response performance. The GOP (possibly the LSE when demand side performance is involved) must be accountable for performing.However, there is nothing in this requirement to encourage the owner of a resource who chooses not to provide frequency response to come to the table. There is nothing in this standard that uniformly requires all frequency response providers to perform. This is likely to be detrimental to the performance of a BAA and unfairly sanctions those willing to perform to to assure reliability while others are not required to perform.
Response: BA is the responsible entity not the BA area **The SDT disagrees with the commenter that putting a specific req on any source could be detrimental to the future development.**		
Ameren	No	The Frequency Response Measure (FRM) definition should include which Entity(ies) it applies to, similar to the definition of the FRO.
Response: if left in modified		
Constellation Energy Commodities Group	No	The Frequency Response Obligation has two components based on Attachment 1 - an Interconnection FRO and a BA FRO. The proposed

Organization	Yes or No	Question 1 Comment
		definition captures only the BA FRO.
Response: definition is only for compliance purposes – no IFRO mandate		
Hydro-Quebec TransEnergie	No	The FRM and FRO definitions should precise that it is expressed in MW/0.1Hz.As for the Frequency Bias Setting definition, as written, would apply only to a multiple BA Interconnection. In a single BA Interconnection, the Frequency Bias translates the frequency error into a MW value that must be dispatched to bring back Frequency to desired value. Since Tie Lines are not controlled through AGC, there is no response withdrawal issue
Response: if definitions left in modified **Disagree that definition is only applicable to multi-BA interconnection**		
Northeast Power Coordinating Council/ISO New England Inc.	No	The FRM definition should not refer to FORM 1. Also, suggest the following wording for frequency bias setting: “A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority’s Area Control Error equation to approximate the frequency response provided by the assets within the respective Balancing Authority’s area.”
Response:		
MRO NSRF	No	The FRM definition: “The median of all the Frequency Response observations reported annually on FRS Form 1” is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an attachment to a standard. In the current NERC Glossary of Terms, there is no such precedence that a definition must rely on the requirements or details in a standard for completeness. Additionally, the definition of Frequency Bias Setting should focus on what it is. Balancing Authorities do not supply energy. Suggest revising it to:Frequency Bias Setting A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a

Organization	Yes or No	Question 1 Comment
		Balancing Authority's Area Control Error equation to approximate the expected natural response provided by the assets within the respective Balancing Authority's area.
Response:		
Alberta Electric System Operator	No	The FRO definition is specific to BAs. The Appendix 1, which is incorporated in the standard, uses this definition in relation to requirements of the Interconnection. The SDT should consider a revision of this definition that accounts for the requirements of the Interconnection versus the BA obligation to the Interconnection.
Response:		
South Carolina Electric and Gas	No	The last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. Therefore, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word "Interconnection". Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?
Response: progress response		
SERC OC Standards Review Group	No	We feel that the last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. While the SERC OC Standards Review Group understands the statement, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word "Interconnection". Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?

Organization	Yes or No	Question 1 Comment
Response: progress response		
Southern Company	No	We suggest adding BA to the definition of Frequency Response Measure (FRM), similar to the definition for Frequency Response Obligation (FRO).
Response:		
Associated Electric Cooperative Inc	Yes	The FRO definition incorrectly applies the historically narrow Balancing Authority scope of responsibility, while the FRM definition does not address applicability at all. But the BAL-003-1 Standard itself identifies RSGs (where applicable) and BAs as the Responsible Entities within scope of this standard. For consistency, AECI recommends using “Responsible Entities (e.g. Reserve Sharing Groups - where applicable, and Balancing Authorities)” in both the FRO and FRM definitions. Rationale: This change should help future-proof the definition, should more specific “frequency response” or “spinning reserve” sharing groups later surface within our industry.AECI agrees with the Frequency Bias Setting definition’s inclusion of a bit more functionality than typical. We however recommend replacing “to account for the Balancing Authority’s Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems”, with “to support their Frequency Response contribution to the Interconnection”. Rationale: Readability, and clarity on the “discouraging withdrawal...” phrase, which should reside in the Background document.
Response:		
SCE&G	Affirmative	The last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. Therefore, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word “Interconnection”. Should the definition for

Organization	Yes or No	Question 1 Comment
		Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)? o The utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as “Frequency Response Sharing
Response:		
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	

Organization	Yes or No	Question 1 Comment
FMPP	Yes	
Xcel Energy	Yes	
Tucson Electric Power	Yes	
NV Energy	Yes	
Cleco Corporation	Yes	
Great River Energy	Yes	
Florida Municipal Power Agency		
JEA Electric Compliance		
Sacramento Municipal Utility District (SMUD)		
Arizona Public Service Company		
American Electric Power		
Texas Reliability Entity		
ReliabilityFirst		

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:

Organization	Yes or No	Question 2 Comment
Seattle City Light	Negative	The language in Requirement 4 needs to be clarified and recommends the following change: R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning]
Response: change made		
Public Utility District No. 1 of Douglas County	Negative	1. Recommend clarifying the language in R1 to include background information as to how RSGs fit into the FRM performance. 2. Recommend R3 language be modified to permit operation in other than tie-line bias mode with the requirement to notify the RC. 3. We have concern about the affect R3 will have on the WECC time error correction standard (BAL-004-WECC-1). 4. Clarification is needed between Attachment A and the Background Document for projected peak and historical peak. 5. We have a concern about the affect of lowering the minimum frequency bias obligation from 1% to .8% and its probable affect on reliability.

Organization	Yes or No	Question 2 Comment
		6. We have a concern about he upper limit to the amount of frequency response expected from BAs.
Response: 1 - RSG under review **2 – modifying** **3 – look at further – the sdt recognizes the obligation of WECC entities** **4 – the sdt has addressed this issue** **5 – white paper** **6 – need to modify to address this concern**		
Potomac Electric Power Co.	Negative	1)The proposed Requirements do not meet all the FERC directives. 2)The proposed Requirements fail to recognize the fact that not all BAs can provide primary frequency response. 3)The proposed Requirements are not all in the standard. Some are in the Attachments.
Response:1 – explain how we have met FERC directives **2 – functional model** **3 – sdt believes req should be succinct – methodology in att**		
Seattle City Light	No	o LADWP and SCL have a concern with Requirement 3. The requirement should provide allowance for legitimate circumstances when an entity cannot run on Tie Line Bias mode and not have an Adverse Reliability Impact on the Balancing Authority's Area. An entity should not be penalized when these legitimate circumstances occur. LADWP believes that the Frequency Response Standard Background Document, on Page 8, lists examples of legitimate circumstances:-Telemetry problems that lead the operator to believe ACE is significantly in error.-

Organization	Yes or No	Question 2 Comment
		The frequency input to AGC is not reflective of the BA's true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection).- During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them).- For training purposes.- Many AGC systems will automatically switch to an alternate mode if the EMS determines Tie Line Bias control could lead to problems. o LADWP and SCL believe that the language in Requirement 4 needs to be clarified and recommends the following change (in red):R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) calculate the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning] o LADWP and SCL believes the language in Requirement 5 needs to be modified to be consistent with that of the second paragraph of Attachment B. SCL recommends the addition of "natural frequency response" as a third bullet item to Requirement 5 (in red). The revised requirement would read: R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following: [Risk Factor: Medium][Time Horizon: Operations Planning] o The minimum percentage of the Balancing Authority Area's estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The minimum percentage of the Balancing Authority Area's estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment

Organization	Yes or No	Question 2 Comment
		B. o The natural frequency response
Response: sdt modifying **R4 modified** **sdt disagrees because suggested change would give BA an option to circumvent the minimum %**		
FMPP	No	o R1. Each Balancing Authority (BA) or Reserve Sharing Group (RSG) shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each BA or RSG to maintain an adequate level of Frequency Response in the Interconnection. [Risk Factor: Medium][Time Horizon: Operations Assessment] The BA does not have control over the frequency responsive generation. There needs to be a requirement that the GOP shall set frequency response for the generators as directed by the BA. o R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is {greater than or (<= add these words)} {at least (<= delete these words)} equal to one of the following: [Risk Factor: Medium][Time Horizon: Operations Planning] o The minimum percentage of the Balancing Authority Area's estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The minimum percentage of the Balancing Authority Area's estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment B.
Response: generically beyond the scope and ultimately detrimental to the reliability		

Organization	Yes or No	Question 2 Comment
modified		
Western Electricity Coordinating Council	No	Agree with the changes made to this latest version of BAL-003-1. However, additional clarity could be added by addressing the following: R1- It is not clear what is intended by "Reserve Sharing Group". As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifiying this concept and possibly include an example in the background document to help explain how this would work. R3 - There may be occasions in which an entity has a legitimate reason or a need to operate in a mode other than Tie Line Bias but that does not qualify as an Adverse Reliability Impact. Recommend including language that would permit limited operation in a mode other than Tie Line Bias mode provided the Reliability Coordinator was notified. R3 - Has the drafting team considered whether or not the language of Requirement R3 will have any conflict or coordination issue with the FERC-approved regional reliability standards BAL-004-WECC-1 - Automatic Time Error Correction? R5 - Suggest changing the language “at least equal to” to “greater than or equal to” for clarity.
Response: R1 – RSG clarification R3 – modifying R5 - modified		
Seattle City Light	Negative	Answer: No Comments: o LADWP and SCL have a concern with Requirement 3. The requirement should provide allowance for legitimate circumstances when an entity cannot run on Tie Line Bias mode and not have an Adverse Reliability Impact on the Balancing Authority’s Area. An entity should not be penalized when these legitimate circumstances occur. LADWP believes that the Frequency Response Standard

Organization	Yes or No	Question 2 Comment
		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. o LADWP and SCL believe that the language in Requirement 4 needs to be clarified and recommends the following change: R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning] o LADWP and SCL believes the language in Requirement 5 needs to be modified to be consistent with that of the second paragraph of Attachment B. SCL recommends the addition of "natural frequency response" as a third bullet item to Requirement 5. The revised requirement would read: R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following: [Risk Factor: Medium][Time Horizon: Operations Planning] o The minimum percentage of the Balancing Authority Area's estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The minimum percentage of the Balancing Authority Area's estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The natural frequency response
Response: check if duplicate from above and remove		

Organization	Yes or No	Question 2 Comment
Avista Corp.	Negative	As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifiying this concept and possibly including an example in the background document to help explain how this would work. Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.
Response: rsg issue **Freq bias setting – theory says that freq bias and natural freq resp are close then best operation – the process developed to reduce the fbs allows for the close monitoring and possible stop - issue**		
City of Redding, Oregon Public Utility Commission, BrightSource Energy, Inc., Clark Public Utilities, Avista, Tri-State G & T Association, Inc.; Deseret Power	Negative	As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly including an example in the background document to help explain how this would work.
Response: rsg response		
Sacramento Municipal Utility District (SMUD)	No	As drafted, requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and

Organization	Yes or No	Question 2 Comment
		appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly including an example in the background document to help explain how this would work.As drafted, in requirement R3, each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired. Recommend including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified.We seek clarification from the drafting team as to whether or not there will be any conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction.
Response: rsg & R3 issue response		
Energy Mark, Inc.	No	Comment 1: The timing requirements for implementing the Frequency Bias Setting are not specified for BAs participating in Overlap Regulation Service. The requirements indicate the value that should be used for the Frequency Bias Setting, but they do not indicate when those settings should be implemented. Comment 2: The term "Tie Line Bias mode" in Requirement R3 is not sufficiently defined to make this requirement enforceable. Any operating mode labeled as "Tie Line Bias mode" on an EMS that uses interchange scheduled and frequency error as inputs will meet the standard requirement as stated. This loop-hole exists because the NERC definition of "Tie Line Bias" fails to define the term in enough detail to actually limit AGC operation to the specified mode of operation. One way to improve this requirement would be to redefine Tie Line Bias in the NERC Glossary as a mode that uses the NERC ACE Equation as defined in BAL-001 as the basis for AGC

Organization	Yes or No	Question 2 Comment
		action when the EMS is in Tie Line Bias mode. Comment 3: The standard is silent on how a BA receiving Overlap Regulation Service should set its Frequency Bias Setting. Unless this is explicitly stated, it will be up to the auditors to determine the value of the Frequency Bias Setting for BAs receiving Overlap Regulation Service. Comment 4: In general, the requirements indicate what the responsible BAs should do and when. The requirements do not indicate what the BAs that are not responsible should do and when, ie. how they are relieved from responsibility. This may create problems when the auditors are required to interpret the standards for BAs that have appropriately shifted responsibilites to others.
Response: comment 1 – modified r2 – review Background\att a to address those receiving **Comment 2 – review definition of tie line bias** **Comment 3 & 4 – issue of receivers of overlap reg service (do we require receivers to have a fbs requirement?)**		
Duke Energy	No	Duke Energy supports the concept of a group of BAs forming a group to share in Frequency Response however it should be clear that it is an option. We feel that the utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms which is specific to sharing of contingency reserves, and should be replaced with a new term, such as “Frequency Response Sharing Group”. R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in “Tie Line Bias” mode.Though comments are provided below on the Attachments, Duke Energy believes that all NERC Reliability Standards’ requirements must reside within the standard itself (which is vetted by the Industry and subject to FERC approval), and not within Attachments that may be revised without Industry review and approval. As noted below and in prior comments, given the secondary control implications of changing the minimum Frequency Bias Setting (FBS), Duke Energy believes that subsequent revisions to the minimum FBS should be

Organization	Yes or No	Question 2 Comment
		vetted through the Standards process. Duke Energy would suggest moving the details of the minimum FBS for each Interconnection into the Standard, and having the implementation plan include annual submittal of a revised minimum FBS based upon the methodology presented in Attachment B for ballot approval by the Industry.
Response: rsg issue response **Your issue addressed by modifying r2** **Req in att response** **Nerc in process of clarifying a process to make modifications to att – added language to att b (OC in collaboration with NERC staff)**		
ISO/RTO Council Standards Review Committee	No	General CommentsThe SRC offers the following general comment with regard to the SDT's proposed revisions: Gerry Cauley's Results based initiative calls for requirements that focus on performance (i.e. WHAT must be accomplished NOT on WHY it is required or HOW it should be accomplished). The SRC has found that such explanatory statements as the SDT is proposing lead to ambiguities and confusion in the compliance application. Compliance Enforcement agents must consider not just the results but must decide if the action was taken for the given reason. To avoid such confusion, the Results based approach uses reference documents to address such background material while leaving the requirement as a direct mandate.The SRC notes: o All NERC Reliability Standards' requirements must reside within the standard itself (which is vetted by the Industry and subject to FERC approval). o Data requirements are better handled through NERC's Rules of Procedure Section 1600 than by mandating that ad hoc Forms be submitted. o Definitions should be generic, and should be self-contained (i.e. should not reference an external document). o The decisions regarding alternative methodologies should be decided by the

Organization	Yes or No	Question 2 Comment
		Industry not by the SDT. The SDT should make its case and ask the Industry for its approval. Regarding Order 693 directives, the SRC notes that there are three directives as follows: (1) To include Levels of Non-Compliance; (2) To determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) To define the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved. The SRC suggests that Directive 2 be handled directly as a mandate that the ERO conduct a fixed number of Frequency Response Surveys for randomly selected events. Discussion of the number and the methodology can be explained in a reference document and leave the specifics to the requirement. Directive 3 is critical to the Industry as it relates to who is the Applicable Entity. The SDT addresses Directive 3 by mandating Balancing Authorities meet an objective. The directive is to define that Objective, but there is no requirement associated with that Objective. There is an attachment and there are discussions of what “may” be done, but there is no requirement in the Standard itself.The reference to the BA as the provider of Frequency Response (i.e. Primary Control response) runs counter to other FERC directives that mandate obligated entities be able to self-serve or to interchange provision of services. In this case the BA per se has no assets and cannot self-serve, moreover the primary response service providers have no obligations to provide the service, thus the BA potentially could face a situation where there is no physical service to be purchased but there is a federally mandated standard to comply with. The idea of creating a Primary Response Market as some have

Organization	Yes or No	Question 2 Comment
		proposed does not work without an obligation on some entity to physically provide that service. One final note, the SRC points out that the ACE is an error signal used to drive secondary response; it is not a signal to drive primary response. Thus the use of the Frequency Bias setting is not for control, it is for “adjusting” the error measure that is analyzed after the fact.This standard needs: o a requirement on the ERO to compute the Obligation on each Interconnection o a requirement on the ERO to conduct Frequency Response surveys (note the SRC does not support this requirement but believes that it is needed to meet the FERC directive) o a requirement on energy supply assets (both generation and load) to provide primary response (as a function of the Interconnection obligation in the first bullet)The above will allow NERC to comply with the FERC directives in a fashion consistent with the processes and procedures approved by FERC.Specific recommendations: The SRC proposes that R1 be deleted based on the facts that: o It imposes an obligation on an entity that has no capability to comply o There is an internal conflict with imposing penalties on a deterministic basis (compliance with a fixed set of events) for a statistical service (primary response is a function of the assets operating state and not a fixed service of the asset).In any case, all of the words after FRO should be deleted. The words are not needed for the requirement and if left in can become a source of contention between auditors and registered entities. R3 - delete the added phrase “mode to effectively coordinate control”.The phrase “would have an Adverse Impact on the BA’s area” needs further discussion. Who makes the decision that operating on AGC will have adverse impact must be defined. R5 - delete the phrase “In order to ensure control response”. Such phrases can be needless causes of debate. If a BA uses one of the bulleted methods but does not get “adequate response” then is the BA non-compliant? What is “adequate

Organization	Yes or No	Question 2 Comment
		response"? Who decides if the response is adequate?
Response: functional model response – comparable to top who does not own capacitors and such but has an obligation to hold a certain level of voltage. **Directive 2 – sdt believes that they are meeting directive** **Directive 3 – amt of fr is defined – measure is defined – methods are included in Background doc and functional model response** **We will relay your concerns about the wording to the SC and QR groups for consideration** **ERO not defined as an applicable entity in the sar – inappropriate to include them**		
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 mode and not have an Adverse Reliability Impact on the Balancing Authority's Area. An entity should not be penalized when these legitimate circumstances occur. LADWP believes that the Frequency Response Standard Background Document, on Page 8, lists examples of legitimate circumstances:- Telemetry problems that lead the operator to believe ACE is significantly in error.- The frequency input to AGC is not reflective of the BA's true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection).- During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them).- For training purposes.- Many AGC systems will automatically switch to an alternate mode if the EMS determines Tie Line Bias control could lead to problems.LADWP believes that the language in Requirement 4 needs to be clarified and recommends the following change:- R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area

Organization	Yes or No	Question 2 Comment
		being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning]LADWP believes the language in Requirement 5 needs to be modified to be consistent with that of the second paragraph of Attachment B. LADWP recommends the addition of “natural frequency response” as a third bullet item to Requirement 5. The revised requirement would read:- R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following: [Risk Factor: Medium][Time Horizon: Operations Planning] o The minimum percentage of the Balancing Authority Area’s estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The minimum percentage of the Balancing Authority Area’s estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The natural frequency response
Response: seattle city response		
MidAmerican Energy Co.	Negative	MidAmerican supports the comments provided by the NSRF. It is not clear if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. It is not clear what will happen if an event occurs in the Eastern Interconnection that causes the frequency to drop to less than 59.6 Hz (e.g. what if freq dips to 59.5). Without a statement that the BA is expected to keep its allocated portion of generation reserves only up to the largest event identified in Table 2, a BA could be expected to provide limitless amounts of frequency response. Balancing Authorities cannot know what is expected of them and therefore cannot plan appropriately.
Response: Dave L response for modified R1		
East Kentucky Power Coop.; ACES Power Marketing;	Negative	Overall, [we] believes the drafting team has done an excellent job to address the FERC directives from Order 693. However, we believe there is still room for

Organization	Yes or No	Question 2 Comment
Hoosier Energy Rural Electric Cooperative, Inc.; Southwest Transmission Cooperative, Inc.		improving the standard and that there is a significant technical error. The technical error was introduced by applying Requirement 1 to the RSG and is discussed below. Requirement 1 should not apply to a Reserve Sharing Group. Reserve Sharing Groups (RSG) are designed to share Contingency Reserves and/or Operating Reserves not Frequency Response. While these reserves may be frequency responsive, they are not being shared for the purpose of expanding frequency response. Furthermore, while reserve sharing groups may calculate a joint ACE by summing its individual BA ACE values, RSGs do not have a Frequency Bias Setting which is necessary to assess a Frequency Response Obligation. Under item 3 of the Event Selection Criteria section, the delta F and Point C should be described either in this attachment or the "Frequency Response Standard Background Document". While many in industry may understand what these terms mean, history has a way of getting lost with personnel turnover. Furthermore, this would help ensure that the auditors and industry have a duplicate understanding. In the Frequency Response Obligation section on page 2, several items require more description. Further description of why an N-2 event was chosen for the Contingency Protection Criteria should be provided and which N-2 event was selected so that industry can help validate if the correct MW value was selected. Furthermore, the document should clarify if the Contingency Protection Criteria contains the "safety margin". There is a statement in the paragraph before the table that states it does, but then the table lists out a separate 25% "Safety Margin". Thus, it is not clear if the "Safety Margin" is included in the Contingency Protection Criteria value listed in the table or not. "Safety margin" should be changed to "reliability margin". Safety has a specific meaning in the electric industry and its use here is not appropriate. The Base Obligation should be explained. The explanation should include its purpose and origin. The Data Retention section requires the BA to retain data or evidence for up to four years. No data that exceeds the audit cycle should be required to be retained. The

Organization	Yes or No	Question 2 Comment
		audit cycle is three years for BAs.
Response: rsg response **Sdt agrees and has modified att a** **Data retention has been modified for clarity**		
PPL Electric Utilities Corp.; PPL Generation LLC	Negative	The PPL Companies do not support proposed Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) primarily because PPL believes it inappropriately subjects Reserve Sharing Groups (RSGs) to the proposed requirements. The proposed Applicability provision states that the mandatory reliability requirements would be applicable to (1) Balancing Authorities and (2) Reserve Sharing Groups (where applicable). However, it is unclear how the proposed requirements would be applicable to an RSG. RSGs typically do not provide a mechanism for sharing automatic Frequency Response. The BA Frequency Response Obligation (FRO) is a formula based on BAs and the Interconnection and has nothing to do with RSGs. Rather, RSGs collectively respond to requests for activation of contingency reserves generally after the request is made by a member Balancing Authority. The Standard Drafting Team should therefore remove RSGs from the Applicability section and should remove all other references to RSGs in the proposed standard.
Response: rsg response		
Progress Energy	No	PGN supports the collective comments of SERC members.We feel that the utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as “Frequency Response Sharing”. R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in “Tie Line Bias” mode

Organization	Yes or No	Question 2 Comment
Response: rsg response **R4 has been addressed by modifying r2**		
MRO NSRF	No	R1- It is not clear what is intended by "Reserve Sharing Group" in this context. As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifiying this concept and possibly include an example in the background document to help explain how this would work. R2 - Please add the word “range” in-between the words “date” and “specified”. The background document specifies that there is a 72-hour period to implement the FBS setting (See Background document Page 7). R2, as written, does not reflect the period for which an entity may implement the ERO validated Bias into ACE. Also see our comment on #7 as to the length of the comment period. Question 7 comment is provided to assist the SDT; Note from question 7: (Page 7 (3rd paragraph) of the Background document states “Given the fact that BA’s can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date. 1. The Standard itself does not state this provision (24 hour window on each side of target date) as indicated. 2. The SDT accurately addresses the fact that BA’s could have EMS or staffing issues during implementation of the ERO validated FBS. The current stated 72-hour window is not long enough for implementation of the FBS as there may be a host of issues that could impact implementation. We suggest that a seven day window be used for implementation of the FBS.) R3 - Recommend the term “Adverse Reliability Impact” be removed from Requirement 3. Based on the NERC definition of the term, a smaller entity could never operate its

Organization	Yes or No	Question 2 Comment
		AGC outside of TLB mode due to their impact on the BES not likely to result in “instability or Cascading”. To ensure a more consistent and equitable approach when applying this Requirement, recommend the drafting team incorporate the reliability reasons listed within the Background Document into the actual Requirement. Additionally, the phrase “effectively coordinated control” should be removed as this is not essential to the Requirement and introduces ambiguity in its application. To this end, the following revisions are proposed: R3. Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area meets one or more of the following conditions. o Telemetry problems that lead the operator to believe ACE is significantly in error. o The frequency input to AGC is not reflective of the BA’s true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection). o During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them). o For training purposes. o Many AGC systems will automatically switch to an alternative mode if the EMS determines Tie Line Bias control could lead to problems. o For single BA Interconnections, Flat Frequency and Tie Line Bias are equivalent. o The Reliability Coordinator has been informed and the duration is [insert time constraint language here]. R5 - Recommend to delete the phrase “In order to ensure control response”. Such phrases can be needless causes of debate. If a BA uses one of the bulleted methods but does not get “adequate response” then is the BA non-compliant? What is “adequate response”? Who decides if the response is adequate? Please clarify.

Organization	Yes or No	Question 2 Comment
Response: rsg response **Modified background to provide clarity & OC operating guide** **R3 being removed – covered in BAL-005 R6 & R7** **NERC requires in guidelines – reliability objective in each req**		
Xcel Energy	No	R1- It is not clear what is intended by "Reserve Sharing Group" in this context. As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifiying this concept and possibly include an example in the background document to help explain how this would work. R3 - recommend modifying the language to permit AGC out of TLB mode if the RC is notified; also remove the "to ensure coordinated control" as this is not essential for the requirement. Our reasoning behind the suggested change to notification of the RC is that there are occassions where an entity would need to perform testing, etc and it could be argued that testing would not be sufficient justification for meeting the Adverse Reliability Impact definition. Here is proposed revised language:Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode, unless the Balancing Authority's Reliability Coordinator has been informed and the duration is [insert time constraint language here].
Response: rsg response **R3 response (removal)**		
Constellation Energy Commodities Group	No	R1 should accommodate agreements between multiple BAs and RSGs in achieving the annual Frequency Response Measure. See proposed modification below: R1. Each Balancing Authority shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or

Organization	Yes or No	Question 2 Comment
		more negative than its Frequency Response Obligations (FRO) to ensure that sufficient Frequency Response is provided by each BA. Either the Balancing Authority individual FRM, multiple Balancing Authority's FRM per written agreement, or the FRM of the Reserve Sharing Group must be equal to or more negative than the applicable Frequency Response Obligations (FRO) for a single Balancing Authority or the aggregate of multiple Balancing Authorities or RSGs.- In R2, "Each Balancing Authority not participating in Overlap Regulation Service" should state "Each Balancing Authority, not receiving Overlap Regulation, shall implement the appropriate Frequency Bias Setting (fixed or variable,) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control". – In R3, the explanatory language about why to operate in Tie Line Bias mode should be deleted. See proposed modification below: R3. Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area.- R5 should be modified to state only that the FBS is specified by the ERO in accordance with Attachment B. As drafted the Requirement is in conflict with Attachment B because the Requirement mandates a minimum and does not allow for a reduction to the minimum but it references Attachment B which is titled "Process for Adjusting Minimum Frequency Bias Setting". See proposed modification below: R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is as specified by the ERO in accordance with Attachment B.- There should be a Requirement specifically stating there is an obligation to complete and submit FRS Form 1 by January 10th each year for clarity.- The requirements should be re-ordered to reflect the chronology of the process for

Organization	Yes or No	Question 2 Comment
		frequency calculation, implementation and performance measurement. The recommended order is as follows: R5 which defines the minimum Frequency Bias Setting (FBS) for a Balancing Authority R4 which describes how the minimum FBS may be altered through Overlap Regulation Service R2 which identifies the coordination required around implementationR3 which requires operation in Tie Line Bias mode R1 which establishes the performance obligation
Response: r1 – modified language – created Freq Resp Sharing Group **R2 – agree and modified** **R3 removal response** **R5 – att b defines inter floor –** **Add req – administrative and sdt did not want to include as part of a performance based std** **Good suggestion – this is a forward looking std (set goal at beginning of year), report performance end of year and calculate bias**		
Constellation Energy	Negative	-R1 should accommodate agreements between multiple BAs and RSGs in achieving the annual Frequency Response Measure. See proposed modification below: R1. Each Balancing Authority shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligations (FRO) to ensure that sufficient Frequency Response is provided by each BA. Either the Balancing Authority individual FRM, multiple Balancing Authority's FRM per written agreement, or the FRM of the Reserve Sharing Group must be equal to or more negative than the applicable Frequency Response Obligations (FRO) for a single Balancing Authority or the aggregate of multiple Balancing Authorities or RSGs. -In R2, "Each Balancing

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

Organization	Yes or No	Question 2 Comment
		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 each BA's FRM can be consistently calculated to a level that will not create false non-compliance to this requirement. While the calculation methodology in FRS Form 1 looks promising, with the A-value and B-value average periods, we believe successful completion of the field trial is prudent. R5. We were not sure if it was intended for this comment question to include Requirement R5, but have decided to include our comments here. While we agree with the requirement of R5, it should not be at the expense of changing the value of L10 in BAL-001, R2, which has been accepted by FERC in Order 693. An accommodation should be made so that any changes to the Frequency Bias Setting according to BAL-003, R5, should not affect the value of L10 used in BAL-001, R2.
Response: agree that validation needs to occur **This sdt can't control what happens in BAL-001 however we intend to monitor the impact of this std on other std's measures.**		
American Electric Power	No	R1: Clarification is needed regarding the responsibility of a BA that is a member of a Reserve Sharing Group. R2 and R3: What does "coordinated control" mean? There no leverage for the BA to require the generator to carry their burden of addressing governor settings or droop settings, yet the BA is obligated to meet some performance measures. 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.

Organization	Yes or No	Question 2 Comment
Response: rsg response **R3 gone – r2 reliability objective statement** **Functional model and Gen req response**		
Great River Energy	No	R1: Including the Reserve Sharing Group (RSG) in the Frequency Response Obligation is outside of the boundaries of a RSG. Where or how would a Frequency Bias be determined for an RSG to determine their Frequency Response Obligation? Although it is apparent that frequency responds during the implementation of reserves, the intention of a RSG is not to share frequency response, but rather to share Reserves. Additionally, if the Frequency Response Obligation is not met by the RSG how are penalties assessed? Should they be assessed to the group as a whole or strictly to the generators that did not meet their individual obligation? R3: Needs to include verbiage for those circumstances when it would be necessary to run AGC out of TLB such as during necessary testing. The BA should have the option to operate out of TLB for a predetermined amount of time if needed when notification and coordination with the RC has been established.
Response: rsg response **Rsg does not have a bias obligation – process further clarified in Background doc** **R3 removed**		
Tucson Electric Power	No	R1: TEP feels that the FRO should be able to be calculated by the BA and that Form 1 changes should be treated via the Standard drafting process. R2: TEP feels that use Form 1 should be required by the Standard. Further, BAs should calculate its own frequency bias setting without ERO intervention. R3: Operating outside Tie Line Bias mode should be allowed during a year to allow for the testing of other modes.

Organization	Yes or No	Question 2 Comment
		R4: Agree with the concept, but without ERO intervention. R5: Should read "greater than or equal to".
Response: r1 – changes to form 1 during field trial will be done via stds drafting process – changes later will be defined by a process described in attachment – changes in inter obligation would be infrequent but would be in accordance with att a – BA fro would be based yearly on ba footprint **R2 – form 1 calculates fbs and the ero needs to validate the data (validation helps bas by correcting bad entries)** **R3 - removed** **R4 – ero does not set fbs just validates – past practices has shown that there are errors in the data** **R5 - modified**		
SCE&G	Affirmative	R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in "Tie Line Bias" mode. o We suggest the SDT consider a term other than "Initial' in the title for Table 1. We suggest "Proposed Frequency Bias Setting" for Table 1 o
Response: agree but corrected wording in r2 **Modified att b**		
Bonneville Power Administration	No	Regarding R1, BPA believes that adding additional requirements in R1 by referencing Attachment A does not add clarity. FRO should be a calculation that the BA's can do themselves and included within the standard. Can Form 1 be changed outside of the standard drafting process? BPA doesn't believe that Form 1 should be allowed to be changed outside of the standard drafting process. As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more

Organization	Yes or No	Question 2 Comment
		towards 'secondary response'. BPA recommends clarifying this concept and possibly including an example in the background document to help explain how this would work. Regarding R2, BPA believes each BA should be able to calculate its own frequency bias setting without ERO validation. The standard can require the BA to use Form 1, if the BA doesn't use Form 1 correctly, then the BA would be in violation of the standard. BPA believes that R3 should include a minimal amount of time (suggesting a couple of hours per year) to allow for testing other modes. Requirement R3 requires each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired. BPA recommends including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified.BPA seeks clarification from the drafting team as to whether or not there will be any conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction. BPA agrees with the concept of R4, however, BPA again disagrees with the ERO validation of the frequency bias setting. BPA believes that reducing frequency bias obligation is detrimental to reliability. It seems that lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. BPA believes that over time, it would seem that this pattern would lead to poorer response. BPA believes that R5 should read "greater than or equal to one of the following" not

Organization	Yes or No	Question 2 Comment
		“ at least equal to”. The requirement should be a part of Form 1 or included in R2. For variable bias, the minimum percentage should be based on the forecasted month peak.
Response: r1 – att will define minor changes – major changes would be through stds process & rsg response **R2 – sdt wants validation not penalty for incorrect data entry** **R3 – removed** **R4 – ero not changing anything just validating –** **R5 - sdt understands your concern and will be monitoring performance – modified req – form 1 does calculate fbs – note to Jamie**		
Manitoba Hydro	No	Regarding R1: 1. Neither R1 nor the referenced Attachment A clarifies the FRM requirements for an RSG to comply versus a BA. In particular (i) At p.3, Attachment A states that the ERO is responsible for “annually assigning an FRO and Frequency Bias Setting to each BA.” No mention is made of RSGs. (ii) Attachment A only references RSGs in the context of reporting obligations for Form 1 (at p.4) and (iii) Compared to BAL-002-0 R1.1, which clearly states that the BA may elect to fulfill its obligation through an RSG and that in such cases the RSG has the same responsibilities as each BA (that is a participant in the RSG). 2. It should be clarified that this requirement applies to a BA, where the BA doesn’t belong to an RSG, OR to an RSG. As it is currently drafted, the standard applies to each BA and each RSG. It is redundant in that each BA would need to comply, whether or not they are a member of an RSG that would also be required to comply. Further, the NERC Glossary definition of an RSG is a group of BAs that collectively maintain, allocate and supply operating reserves. No mention is made of the

Organization	Yes or No	Question 2 Comment
		agreement including the sharing or delegation of responsibility related to FRM. Accordingly, the standard should only reference a BA being able to delegate responsibility to an RSG if the RSG Agreement allows for such delegation. 3. R1 does not specify where or how the FRO is determined. Presumably this would be determined by the ERO pursuant to Attachment A. 4. The phrase "to ensure that sufficient Frequency Response ..." should be separated from the requirement as it is (i) not descriptive of the required actions; (ii) redundant with the stated purpose at the beginning of the standard. In general, such a drafting technique should be avoided as it may allow Responsible Entities to argue that a violation has not occurred where the specific action that is described has not been taken, but the purpose referenced in the requirement has been met. Regarding R2: 1. It is not clear from R2 who determines the Frequency Bias Setting for "validation" by the ERO and how the FBS is determined. (Presumably done by the BA in accordance with Attachment B). Based on Background document, should refer to those "published" by ERO. The BA's FBS may not be validated, and may be modified before posting. 2. Attachment B does not refer to the ERO "validating" FBS. 3. Attachment B refers to an RSG calculating FBS, but the standard does not.

Response: 1 & 2 – RSg response

3 – process for determining fro is in att a –

4 – objective response

R2 – 1 – fbs is determined by the calculation of frm (form 1) – ero will not be making changes in a vacuum the will be working with

Organization	Yes or No	Question 2 Comment
the BA to correct errors. **2 – sdt will provide clarity on rsg reporting and ero validation**		
NV Energy	No	Requirement 1 seems to be the only one that has any applicability to an RSG; however, it is unclear under what circumstances this requirement applies to an RSG. Suggest changing the R1 to be addressed solely to BA's or alternatively, explain under Applicability section 1.2 what "where applicable" means.
Response:		
ACES Power Marketing Standards Collaborators	No	Requirement 1 should not apply to a Reserve Sharing Group. Reserve Sharing Groups (RSG) are designed to share Contingency Reserves and/or Operating Reserves not Frequency Response. While these reserves may be frequency responsive, they are not being shared for the purpose of expanding frequency response. Furthermore, while reserve sharing groups may calculate a joint ACE by summing its individual BA ACE values, RSGs do not have a Frequency Bias Setting which is necessary to assess a Frequency Response Obligation.
Response:		
City of Redding, Oregon Public Utility Commission, BrightSource Energy, Inc., Clark Public Utilities, Avista, Tri-State G & T Association, Inc.; Deseret Power	Negative	Requirement R3 requires each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired. Recommend including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified.
Response:		

Organization	Yes or No	Question 2 Comment
Alberta Electric System Operator	No	The language used in the requirements is superfluous. This could result in confusion and incorrect assumptions being made. In R1, the comment within brackets "(as detailed in Attachment A and calculated on FRS Form 1)", is not necessary as it is already part of the FRM definition. We suggest removing this bracketed text from the requirement. Also in R1, the phrase "to ensure that sufficient Frequency Response is provided by each BA or RSG to maintain an adequate level of Frequency response in the Interconnection" is a high level objective that does not add clarity to this requirement. We suggest removing this from the requirement. R2, R3 and R5 use similar language e.g. "to ensure effectively coordinated Tie Line Bias control", "to ensure adequate control response" etc. Although it provides background information, this does not add clarity to the requirement. We suggest removing these from the requirements.
Response:		
Hydro-Quebec TransEnergie	No	The objective of R2 is that all BA's implement their new Bias Setting at the same time, based on the previous year's data, so that control stays the most effective throughout the Interconnection (Tie-Line Bias). In addition, the new Bias will be in effect all year long. The process is quite simple and straightforward for a fixed Bias Setting. As for Variable Bias Setting, this process is not applicable before the fact since the Bias equation can depend on real-time values that are not known in advance. In addition, the simultaneous Bias implementation is not an issue for a single BA Interconnection. Therefore, we suggest that Requirement 2 applies only to Fixed Bias Setting.
Response:		
Northeast Power Coordinating	No	The requirements should not be directed at Balancing Authorities, as generators are

Organization	Yes or No	Question 2 Comment
Council		the main supplier of “discretionary” frequency response. Requirement R1 refers to an attached form, which is not part of the standard and therefore not enforceable.
Response:		
Beaches Energy Services; City of Bartow, Florida; Tampa Electric Co.	Negative	The standard is silent on the “methods to obtain Frequency Response”. For instance, the BA does not have authority over governor and other generator settings. There should be a requirement for GOPs to incorporate setting changes directed by the BA, otherwise the standard establishes requirements that BAs may not have the authority to achieve. R1 includes the Reserve Sharing Group in its applicability, but none of the other requirements do. There is no consideration of "footprint" changes of the BA resulting in different allocation from the ERO during a year. The standard and Attachments seem to specify an annual process with due dates in December and January with no allowance for mid-year changes and associated allocation changes. If a standard has a requirement for the ERO, who will audit the ERO for compliance? If the ERO does not meet its obligations, can an entity still be found non-compliant, especially on a schedule basis? Wasn’t there an issue of assigning standards to RROs, e.g., the fill-in-the-blank standards? Are there similar issues with assigning requirements to the ERO? Is the ERO a “user, owner or operator” of the BPS under Section 215, e.g., at (b)(1)”... All users, owners and operators of the bulk-power system shall comply with the reliability standards that take effect under this section.” I question how this would work from a compliance perspective. On R5, the wording should be changed from “absolute value is at least equal to” to “absolute value is greater than or equal to”
Response:		
South Carolina Electric and Gas	No	The utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as “Frequency Response Sharing”. R4 should clarify that a BA performing Overlap Regulation Service should still be

Organization	Yes or No	Question 2 Comment
		required to operate its AGC in "Tie Line Bias" mode.
Response:		
Tri-State G & T Association, Inc.; Tucson Electric Power Co.; U.S. Army Corps of Engineers; South California Edison ; Platte River Power Authority; Pacific Gas and Electric Company; Colorado Springs Utilities; Idaho Power Company; California Energy Commission; California ISO; Deseret Power	Negative	We believe that there are several modifications that, if implemented to the existing requirements, would result in an improved, clarified standard. As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifiying this concept and possibly including an example in the background document to help explain how this would work. Requirement R3 requires each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired. Recommend including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified. We seek clarification from the drafting team as to whether or not there will be any conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction.
Response:		
ISO New England Inc	No	We do not agree with placing a requirement on Balancing Authorities, as generators are the main supplier of "discretionary" frequency response. Also, the requirement refers to an attached form, which is not part of the standard and therefore not enforceable.

Organization	Yes or No	Question 2 Comment
Response:		
SERC OC Standards Review Group	No	We feel that the utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as “Frequency Response Sharing”. R2 exempts BAs participating in Overlap Regulation Service from implementing the Frequency Bias Setting on the date specified by the ERO, and R4 states how the BA performing Overlap Regulation Service will modify its Frequency Bias Setting but does not state when the setting will be implemented. The exemption for BAs participating in Overlap Regulation Service should either be deleted from R2 or language stating the implementation date of the frequency bias setting needs to be included in R4. R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in “Tie Line Bias” mode.
Response:		
Florida Municipal Power Agency/JEA Electric Compliance	No	We thank the SDT for their hard work and diligence in moving this Project forward. However, we have some concerns that cause us to not support the standard in its current form.In general, we believe that there has not been sufficient prudency review for the standard, especially R1, to justify a performance based standard around a Frequency Response Measure. We also believe that the proposed standard does not meet all of the conditions of the Final SAR and Supplemental SAR.The “Final SAR” was to develop methods by which a performance based standard would eventually be developed. The Final SAR states:”The proposed standard’s intent is to collect data needed to accurately model existing Frequency Response. There is evidence of continuing decline in Frequency Response in the three Interconnections over the past 10 years, but no confirmed reason for the apparent decline. The proposed standard requires entities to provide data so that Frequency Response in each of the Interconnections can be modeled, and the reasons for the decline in Frequency Response can be identified. Once thereasons for the decline in Frequency

Organization	Yes or No	Question 2 Comment
		Response are confirmed, requirements can be written to control Frequency Response to within defined reliability parameters.”BAL-003-1 does not seem to complete the scope of this “Final SAR”. For instance, “the reasons for the decline in Frequency Response” were not confirmed to our knowledge; and the field trial is not completed to our knowledge.The Supplemental SAR adds to the scope of the Final SAR:”To provide a minimum Frequency Response Obligation for the Balancing Authority to achieve, methods to obtain Frequency Response and provide a consistent method for calculating the Frequency Bias Setting for a Balancing Authority. In addition, the standard will specify the optimal periodicity of Frequency Response surveys.”The Supplemental SAR does not eliminate the pre-requisite contained in the Final SAR to determine the reasons for the decline in frequency response and confirm them before establishing “defined reliability parameters”.In addition, the standard does not complete the requirement of the Supplemental SAR to identify “methods to obtain Frequency Response”. For instance, neither the BA nor the RSG have authority over governor and other generator settings. There should be a requirement for GOPs to incorporate setting changes directed by the BA, otherwise the standard establishes requirements that BAs and RSGs may not have the authority to achieve.There is no consideration of "footprint" changes of the BA resulting in different allocation from the ERO during a year. The standard and Attachments seem to specify an annual process with due dates in December and January with no allowance for mid-year changes and associated allocation changes.If a standard has a requirement for the ERO, who will audit the ERO for compliance? If the ERO does not meet its obligations, can an entity still be found non-compliant, especially on a schedule basis? Wasn’t there an issue of assigning standards to RROs, e.g., the fill-in-the-blank standards? Are there similar issues with assigning requirements to the ERO? Is the ERO a “user, owner or operator” of the BPS under Section 215, e.g., at (b)(1)”... All users, owners and operators of the bulk-power system shall comply with the reliability standards that take effect under this section.” We question how this would work from a compliance perspective.

Organization	Yes or No	Question 2 Comment
Response:		
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	
ERCOT		
Texas Reliability Entity		
ReliabilityFirst		
Arizona Public Service		

Organization	Yes or No	Question 2 Comment
Company		
Southern Company		
FPL		

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:

Organization	Yes or No	Question 3 Comment
Seattle City Light	Negative	Answer: Yes. Comments: LADWP and SCL agree with the following VRFs: - R1 - Medium - R2 - Medium - R3 - Medium - R4 - Medium - R5 - Medium
Response:		
Energy Mark, Inc.	No	Comment 5: See comments in the non-binding poll.
Response:		
Florida Power & Light Company	No	Could not find the Risk Severity Levels in the documents.
Response:		
Cleco Corporation	No	Please note Cleco does not use the VRFs therefore we feel too much energy and time is spent on the VRFs. The SDT needs to concentrate on the requirements and measurements.
Response:		
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.

Organization	Yes or No	Question 3 Comment
Response:		
Seattle City Light/Los Angeles Department of Water and Power	Yes	LADWP and SCL agree with the following VRFs:- R1 - Medium- R2 - Medium- R3 - Medium- R4 - Medium- R5 - Medium
Response:		
NV Energy	Yes	Medium appears to be reasonable and appropriate.
Response:		
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	Yes	

Organization	Yes or No	Question 3 Comment
Standards Collaborators		
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Progress Energy	Yes	
Southern Company	Yes	
FMPP	Yes	
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	Yes	

Organization	Yes or No	Question 3 Comment
Commodities Group		
Great River Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Duke Energy	Yes	
Keen Resources Asia Ltd.	Yes	
Western Electricity Coordinating Council		
Florida Municipal Power Agency		
JEA Electric Compliance		
Sacramento Municipal Utility District (SMUD)		
Arizona Public Service Company		
FPL		
Xcel Energy		
ERCOT		
Texas Reliability Entity		

Organization	Yes or No	Question 3 Comment
Alberta Electric System Operator		
ReliabilityFirst		

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:

Organization	Yes or No	Question 4 Comment
Seattle City Light	Negative	Answer: No. Comments: LADWP and SCL recommend that the Measures for Requirement 3 and Requirement 5 reflect their comments to Question 2.
Response:		
Constellation Energy Commodities Group	No	Based on language modifications proposed to the Requirements, the measures should be revisited.
Response:		
Xcel Energy	No	Based on our suggested changes to R3 in response to Question 2, the drafting team should modify M3 to be consistent with the proposed language.
Response:		
MRO NSRF	No	Based on suggested changes to R3 in response to Question 2, the drafting team should modify M3 to be consistent with the proposed language. Additionally, M1 should be revised to not reference a specific Form. The Form may be the format of choice but it should not be an implied requirement.Measures 3 and 4 identify the use of “operating logs” as evidence. Measure 2 identifies hard copy and electronic evidence, “or other evidence”. We suggest calling out specifically “operator logs” for M2 also, in case there are system problems in capturing hard copy or electronic evidence during the short time window for implementation.

Organization	Yes or No	Question 4 Comment
Response:		
Bonneville Power Administration	No	BPA believes that historian data should be able to be used for evidence.
Response:		
Manitoba Hydro	No	It should be clarified that R1 requirement applies to a BA, where the BA doesn't belong to an RSG, or to an RSG. As it is currently drafted, the standard applies to each BA and each RSG. It is redundant in that each BA would need to comply, whether or not they are a member of an RSG that would also be required to comply. Further, the NERC Glossary definition of an RSG is a group of BAs that collectively maintain, allocate and supply operating reserves. No mention is made of the agreement including the sharing or delegation of responsibility related to FRM. Accordingly, the standard should only reference a BA being able to delegate responsibility to an RSG if the RSG Agreement allows for such delegation.
Response:		
Tucson Electric Power	No	It should be clear that historical data may be used to show compliance.
Response:		
Seattle City Light/ Los Angeles Department of Water and Power	No	LADWP and SCL recommend that the Measures for Requirement 3 and Requirement 5 reflect their comments to Question 2.
Response:		
ISO/RTO Council Standards Review Committee	No	M1: The measure should not be tied to a specific Form. If a BA has the evidence but does not provide it on a given Form, how is the reliability of the Power System

Organization	Yes or No	Question 4 Comment
		impacted? The Form may be the format of choice but it should not be an implied requirement.M4: This measure does not read quite right. Something seems to be missing in the part that says: "...showing when Overlap Regulation Service is provided including Frequency Bias Setting calculation to demonstrate compliance with Requirement R4." This part might have read something like: "...showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation or it calculated the Frequency Bias Setting meeting the conditions specified in Requirement R4."
Response:		
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." This part might have read something like: "...showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation or it calculated the Frequency Bias Setting meeting the conditions specified in Requirement R4."
Response:		
ERCOT	No	Measure should be modified to align with revised Requirements per ERCOT's comments on #1.
Response:		
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".

Organization	Yes or No	Question 4 Comment
Response:		
Northeast Power Coordinating Council/ISO New England Inc.	No	The sampling interval needs to be tuned on a per Interconnection basis to support HQTE's characteristics.
Response:		
Florida Power & Light Company	No	What is meant by documented formulae for M5? Is a one time snapshoot of the AGC formual sufficien? The concept is ok but this needs clarification of proof.
Response:		
Southwest Power Pool Regional Entity	Yes	Measures are more specific and measurable than seen in the past. This is a positive improvement.
Response:		
Ameren	Yes	With the understanding that any suggested changes to the proposed requirements would come with corresponding changes to their measure.
Response:		
Imperial Irrigation District	Yes	
SPP Standards Review Group	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 4 Comment
Energy Mark, Inc.	Yes	
FMPP	Yes	
Associated Electric Cooperative Inc	Yes	
NV Energy	Yes	
Cleco Corporation	Yes	
Great River Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Keen Resources Asia Ltd.	Yes	
Western Electricity Coordinating Council		
Florida Municipal Power Agency		
JEA Electric Compliance		
Sacramento Municipal Utility District (SMUD)		
Arizona Public Service Company		

Organization	Yes or No	Question 4 Comment
Southern Company		
FPL		
American Electric Power		
Texas Reliability Entity		
Alberta Electric System Operator		
ReliabilityFirst		

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:

Organization	Yes or No	Question 5 Comment
Seattle City Light	Negative	Answer: No. Comments: LADWP and SCL recommend that either the VSL for Requirement 3 reflects its comments to Question 2, or that these comments be addressed as an exception in the Measure for Requirement 3.
Response:		
Public Utility District No. 1 of Douglas County	Negative	1. The BA and interconnection meet the FRO differently. Suggest removing the interconnection performance from the VSL and develop additional levels of BA failure to meet its FRO.
Response:		
BrightSource Energy, Inc.	Negative	The negative vote from BrightSource is related to the proposed VSL only. The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO. Conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.
Response:		

Organization	Yes or No	Question 5 Comment
U.S. Army Corps of Engineers; Platte River Power Authority; Pacific Gas and Electric Company; Idaho Power Company; Colorado Springs Utilities; California Energy Commission; California ISO; Clark Public Utilities; Tucson Electric Power Co.; Tri-State G & T Association, Inc.	Negative	The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO. Conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.
Response:		
Kansas City Power & Light Co.	Negative	The VSL for Requirement 3 does not sufficiently reflect a thoughtful range of violation severity of duration or number of instances by which AGC is not in Tie-Line Bias mode.
Response:		
ACES Power Marketing; East Kentucky Power Coop.; Hoosier Energy Rural Electric Cooperative, Inc.	Negative	The VSLs on for Requirement R1 set a previously un-established precedent of relying on the performance of other registered entities to establish the severity level of the violation. This is not appropriate. The VSLs should be rewritten to provide further gradations of the violation severity based on the BA's own performance.
Response:		
Southwest Transmission Cooperative, Inc.	Negative	The VSLs on for Requirement R1 set a previously un-established precedent of relying on the performance of other registered entities to establish the severity level of the violation. This is not appropriate. The VSLs should be rewritten to provide further gradations of the violation severity based on the BA's own

Organization	Yes or No	Question 5 Comment
		performance. The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO. Conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.
Response:		
Western Area Power Administration	Negative	Under compliance for R1, there is a difference between VSL levels whether the interconnection met is FRO or not. If the interconnection meets it's FRO but a single BA doesn't't meet its share of FRO the violation is considered low VSL, but, if the interconnection dosen't't meet it's FRO the same BA will have a High VSL. Obligation of the individual BA to meet its allocated FRO should always be applicable regardless of what other BAs are doing in the interconnection. This provision creates a disparity amongst BAs and creates a disparate treatment between the BAs who perform compared to those who don't.
Response:		
Ameren Services; Ameren Energy Marketing Co./Ameren	Negative/No	It is not clear how the VSL for R1 uses the "Summation of the BA's FRM", when the requirement is BA or RSG specific.
Response:		
Manitoba Hydro	Negative/No	The Violation Severity Levels for R1 penalize entities more severely depending on how the interconnection as a whole has performed. MH believes that BAs should only be held accountable for issues within their control and that the VSLs for R1

Organization	Yes or No	Question 5 Comment
		should be revised accordingly.
Response:		
Constellation Energy Commodities Group	No	The language in the VSLs for R1 should be revisited based on the proposed language modifications above and should also clearly look to the FRM of a BA, group of BAs or RSG against the BA FRO not an Interconnection FRO.
Response:		
Bonneville Power Administration	No	BPA believes that R1 needs to be more clear and concise as to what is being conveyed in the requirement. It is difficult to understand. The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO.BPA believes that conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.
Response:		
Florida Power & Light Company	No	For R1 the low and high level descriptions appear to be identical and the high level is less than the medium risk level. For R3 there should be low, medium, and high levels. One BA not operating to TLB does not jepordize the Interconnection. Additionally, computer failures, database loads etc may require some period where TLB is not in service. Suggestion would be Lower VSL operation off of TLB for more than 5 but < 8 continuous hours or accumlative during the year of more than 8 < 16 hours. Medium VSL would be operation off of TLB for more than 8 but <16 continuous hours or accumlative during the year of more than 16 <24 hours. High

Organization	Yes or No	Question 5 Comment
		VSL would be operation off of TLB for more than 16 <24 continuous hours or accumlative during the year of more than 36 <48 hours. Severe VLS would be >24 continuous hours off of TLB or accumlative of > 48.
Response:		
NV Energy	No	For R1, suggest that the VSL's not be dependent upon the aggregate performance of the BA's within an interconnection.
Response:		
American Electric Power	No	It is not clear for R1 what the exact delineations are among Lower, Medium, High, and Severe VSL’s.
Response:		
Seattle City Light	No	LADWP and SCL recommend that either the VSL for Requirement 3 reflects its comments to Question 2, or that these comments be addressed as an exception in the Measure for Requirement 3.
Response:		
Los Angeles Department of Water and Power	No	LADWP recommends that either the VSL for Requirement 3 reflects its comments to Question 2, or that these comments be addressed as an exception in the Measure for Requirement 3.
Response:		
ReliabilityFirst	No	ReliabilityFirst thanks the SDT for their effort on this project. ReliabilityFirst has a number of concerns/questions related to the draft BAL-003-1 VSLs which include the following:1. General VSL Comment - For consistency with other standards, each VSL should begin with the phrase “The Responsible Entity...” or “The Balancing

Organization	Yes or No	Question 5 Comment
		Authority". This is consistent with the language of the requirement and correctly pinpoints the appropriate responsible entity. 2. VSL R1 Comment - Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement". ReliabilityFirst suggests the following modification:a. Lower VSL - The Responsible Entity achieved an annual FRM within an Interconnection that was equal to or more negative than the Interconnection's FRO and the Responsible Entity's FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FROb. Medium VSL - The Responsible Entity achieved an annual FRM within an Interconnection that was equal to or more negative than the Interconnection's FRO and the Responsible Entity's FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever one is the greater deviation from its FROc. High VSL - The responsible entity failed to achieve an annual FRM that is equal to or more negative than its FRO and the Responsible Entity's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FROd. Severe VSL - The responsible entity failed to achieve an annual FRM that is equal to or more negative than its FRO and the Responsible Entity's FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO3. VSL R4 Comment - Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement". ReliabilityFirst suggests the following modification:a. Example for Lower VSL which should be carried throughout all four VSLs - The Balancing Authority incorrectly modified the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than 5% of the validated or calculated value4. VSL R5 Comment - Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement". ReliabilityFirst suggests the following modification: a. Example for Lower VSL which should be carried throughout all four VSLs - The Balancing Authority used a monthly average Frequency Bias Setting whose absolute

Organization	Yes or No	Question 5 Comment
		value was less than or equal to 5% below the minimum specified by the ERO.
Response:		
Progress Energy / South Carolina Electric and Gas/Duke Energy	No	See comments in Question 2 regarding utilization of the term “Reserve Sharing Group”.
Response:		
SERC OC Standards Review Group	No	See comments in Question 2 regarding utilization of the term “Reserve Sharing Group”.VSL for R1:The draft VSLs for R1 uses the summation of FRM for all BAs within an Interconnection as a factor in determining the applicable VSL. This does not seem consistent with R1. R1 is about a single BA and the individual BA’s frequency response performance as measured by the FRM for that specific BA. Including the FRM summation of the Interconnection expands R1. It appears that a BA that is non-compliant with R1 could end up with either a Low/Medium or High/Severe VSL based upon the FRO performance of the Interconnection. The FRM performance of the Interconnection is beyond the knowledge and control of a single BA and should not be a determinate of the applicable VSL.Is there a technical basis for selection of the 1%, 30% and 15MW/.1 Hz VSL breakpoints? Does the Lower VSL give a 1% dead band to a BA’s FRO? If so, will this be acceptable to NERC/FERC?VSL for R2:The VSL should reflect the language used in the requirement. R2 says a BA “not participating in Overlap Regulation service shall ....”, while the VSL says a BA “not receiving Overlap Regulation Service.....” The VSL language is not consistent with the requirement. VSLs for R5:Since Frequency Bias Setting is expressed as a negative value, the terms “absolute value” and “less than” must be used carefully. Wouldn’t the “absolute value” of a BA’s Frequency Bias Setting always be positive and thus it could never be less than the minimum specified by the ERO (a negative value)?

Organization	Yes or No	Question 5 Comment
Response:		
Western Electricity Coordinating Council	No	The proposed VSLs for Requirement R1 treat a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO.
Response:		
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.
Response:		
Northeast Power Coordinating Council	No	The violation severity levels for R1 are reasonable. The technical writing needs to be enhanced for clarity.
Response:		
ISO New England Inc	No	The violation severity levels for R1 seem to be reasonable. However, the technical writing needs to be enhanced for clarity
Response:		
SPP Standards Review	No	The VSLs for R2 are based on 5, 15 and 25 days. What was the justification for these

Organization	Yes or No	Question 5 Comment
Group/Cleco Corporation		values? Could we just as well use 10, 20 and 30 or some other set of values? In R3, we understand that brief periods of operation outside of TLB control are allowable providing 1) continued operation in TLB control would create ARI on the Interconnection or 2) that justification is provided for the periods when TLB is not used. For example, if something happens within our EMS that disables TLB control are we compliant if we document the period as an EMS malfunction?
Response:		
ACES Power Marketing Standards Collaborators/Great River Energy	No	The VSLs on for Requirement R1 set a previously un-established precedent of relying on the performance of other registered entities to establish the severity level of the violation. This is not appropriate. The VSLs should be rewritten to provide further gradations of the violation severity based on the BA's own performance.
Response:		
Southern Company	No	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 ....'VSLs for R5:Since Frequency Bias Setting is expressed as a negative value, the terms "absolute value" and "less than" must be used carefully. This VSL uses "absolute value" when referring to the BA's Frequency Bias Setting, but does not use "absolute value" when referring to the Frequency Response Obligation, or minimum value specified by the ERO. Consider revising this VSL so that a true comparison can be made.
Response:		
Tucson Electric Power	No	VSL's could be clearer and simpler. Allowance for the testing of other AGC modes should be considered.

Organization	Yes or No	Question 5 Comment
Response:		
Southwest Power Pool Regional Entity	Yes	Hard to follow the language for the VSL for R1. Suggest using formulas for ease of interpretation or provide an example in the Supporting Documentation.
Response:		
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.
Response:		
ISO/RTO Council Standards Review Committee	Yes	We do not have any issues with the VSLs, but wonder if the wording for R1 should have been "...Reserve Sharing Group's...". Alternatively, the wording after "interconnection's FRO" could be revised to: "...and the Balancing Authority's or the Reserve Sharing Group's FRM was..."
Response:		
Independent Electricity System Operator	Yes	We do not have any issues with the VSLs, but wonder if the wording for R1 should have been "...Reserve Sharing Group's...". Alternatively, the wording after "interconnection's FRO" could be revised to: "...and the Balancing Authority's or the Reserve Sharing Group's FRM was..."
Response:		
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."

Organization	Yes or No	Question 5 Comment
Response:		
Imperial Irrigation District	Yes	
Salt River Project	Yes	
Energy Mark, Inc.	Yes	
FMPP	Yes	
Xcel Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Keen Resources Asia Ltd.	Yes	
Florida Municipal Power Agency		
Sacramento Municipal Utility District (SMUD)		
Arizona Public Service Company		
FPL		
ERCOT		
Alberta Electric System Operator		

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:

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 0.1 of HZ) and is allocating it among all BAs. The individual BA's allocated FRO is much lower than what BAs obligations' presently are since the proposed standard lowers the bar for the BAs. The current approach is definitely superior to what is proposed since it more closely matches with the characteristic of the system and it protect the interconnection by requiring larger contribution than proposed standard. 5. The allocation of FRO among the BAs in the interconnection favors the BAs with more load than more installed capacity
Response: 4) fro and fbs not same thing – fro, at least beginning, will be significantly lower than fbs 5) provides an obligation to all bas across interconnection – gen only & load only (mix of two) generally provides proportional obligation		
Seattle City Light	Negative	Answer: No. Comments:

Organization	Yes or No	Question 6 Comment
		o LADWP and SCL consider the increase in number of events to analyze (now 25) to be excessive. Previous years analyses typically involved 4-6 events; a permanent five-fold increase is not justified. SCL suggests reducing the baseline number of events from 25 to 12 per year. Analysis of a larger number of events could be requested on a year-by-year basis if conditions warrant, but should not be mandatory for all regions in all years.
Response: our studies have shown that frm converges well after 20 samples given the large noise – smaller sample size would put bas at risk for failure to comply due to error in the calculation – the evaluation is being used for more than previously		
Alliant Energy Corp. Services, Inc.	Negative	Confusion exists around the "peak load" in that Attachment A states the allocastion is based on Projected Peak Loads and Generation but the Background Document states it will use historical Peak and Generation to make the allocation. - There appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same approach. If installed capacity is used in the equation in Attachment A, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity of something less - please clarify. – It is not clear if there is an upper limit to the amount of frequcncy response expected of the BA's under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of FR expected on a total basis. BA's need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet the requirements.
Response: allocation methodology **Dave L**		
BrightSource Energy, Inc.; Clark Public Utilities; Tri-State G & T Association, Inc.; Tucson	Negative	Confusion exists between Attachment A and the Background Document. Attachment A states peak load allocation is based on “Projected” Peak Loads and Generation, but the Background Document states it will use “historical” Peak Load and Generation.

Organization	Yes or No	Question 6 Comment
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		Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response. The standard is unclear as to if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of Frequency Response expected on a total basis. Balancing Authorities need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet this requirement. The documents do not appear to provide any boundary on the maximum amount of Frequency Response that a BA will provide, i.e. it is not clear what will happen if an event occurs in the Eastern Interconnection that causes the frequency to drop to less than 59.6 Hz or in the Western Interconnection that causes the frequency to drop to less than 59.5 Hz, or if that event is excluded from the list used to calculate the Balancing Authorities' response or is it included with an expectation that it counts the same as any other event. Without a clear statement of what is expected, including whether there is a limit on that expectation or not, it is unclear what is expected of the Balancing Authorities. Finally, why are there no requirements on governor installation, settings, and operation for a frequency response standard?
Response: corrected – allocation **Minimum fbs** **Dave L** **Generator req**		
Beaches Energy Services; City	Negative	On Event Selection Criteria, bullet 2, if 25 events cannot be identified then the ERO

Organization	Yes or No	Question 6 Comment
of Bartow, Florida; Tampa Electric Co.		can go back in time to the previous year. This creates a double jeopardy to R1 of the standard. It also may include irrelevant data if there have been changes from one year to the next in FRO or Bias settings assigned by the ERO. On Frequency Response Obligation, first paragraph states that "Each Interconnection will establish target contingency protection criteria"; however, the Interconnection is not a decision-making body. Does this really mean the ERO will establish FRO for each Interconnection? The single asterisk note for the table on page 2 states: "It is extremely unlikely that an event elsewhere in the Eastern Interconnection would cause the Florida UFLS special protection scheme to “false trip”.", "Special protection scheme" should be stricken from this sentence, Florida has just a regional difference in its UFLS program.
Response: recommending what we are recommending???? **Modified statement** **SPS deleted**		
Salmon River Electric Cooperative	Negative	We feel that the drafting team has done an excellent job of providing clarify and reasonable reporting requirements to the right functional entity. We support the modifications but would like to have two additional minor modification in order to provide additional clarification to the Attachment I Event Table. We suggest the following clarifications: For the Event: BES Emergency resulting in automatic firm load shedding Modify the Entity with Reporting Responsibility to: Each DP or TOP that experiences the automatic load shedding within their respective distribution serving or Transmission Operating area. For the Event: Loss of Firm load for = 15 Minutes Modify the Entity with Reporting Responsibility to: Each BA, TOP, DP that experiences the loss of firm load within their respective balancing, Transmission operating, or distribution serving area. With these modifications or similar modifications we fully support the proposed Standard.

Organization	Yes or No	Question 6 Comment
Response: wrong std		
FMPP	No	o Item 2 should be changed as follows: The ERO will identify at least 25 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify in a given evaluation period 25 frequency excursion events satisfying the limits specified in criteria 3 below, then similar acceptable events from the previous evaluation period also satisfying listed criteria will be included with the data set by the ERO for determining FRS compliance. (as written this item could cause double jeopardy for event from the previous period) o Under FRO for the Interconnection the first sentence should be changed as follows: "The ERO {Each Interconnection (delete these words)} will establish target contingency protection criteria for each Interconnection." (each Interconnection is not a governing entity) o The footnote under Table 2 of Attachment A should be changed as follows: The Eastern Interconnection set point listed is a compromise value for the highest UFLS step setting of 59.5Hz used in the east and the {special protection scheme's (delete these words)} highest UFLS step setting of 59.7Hz used in Florida. It is extremely unlikely that an event elsewhere in the Eastern Interconnection would cause the Florida UFLS {special protection scheme (delete these words)} to "false trip". (this is not a special protection system; it is just an UFLS)
Response: 25 event response **Modified wording** **Modified footnote**		
Seattle City Light	No	o LADWP and SCL consider the increase in number of events to analyze (now 25) to be excessive. Previous years analyses typically involved 4-6 events; a permanent five-fold increase is not justified. SCL suggests reducing the baseline number of events from 25 to 12 per year. Analysis of a larger number of events could be requested on a

Organization	Yes or No	Question 6 Comment
		year-by-year basis if conditions warrant, but should not be mandatory for all regions in all years.
Response: lawp response		
Manitoba Hydro	No	1. p.2 refers to each “Interconnection” establishing target contingency protection criteria. However, an “Interconnection” as defined in the NERC Glossary is an electrical system, not a Responsible Entity. This should be revised to clarify which Responsible Entities must establish the protection criteria. 2. Table 2, although entitled “Interconnection Frequency Response Obligations” does not use the term FRO in the Table itself. This terminology should be consistent. 3. There is no clear statement in Attachment A identifying the significance of Table 2. The previous paragraph identifies Table 2 as listing “default targets”, but how does this relate to the FRO referenced in R1? 4. The “Note” on p.2 regarding the ERO being able to use additional events that don’t satisfy the criteria is unreasonable as drafted. Since these events are used to calculate the Frequency Bias Setting and FRM (as per p.1, s.2), the selection of events should not be at the unfettered discretion of the ERO. As drafted, no grounds or criteria must be satisfied.
Response:1. Modified language **2. made consistent** **3. modified** **4. revisit after R1 VSL decision**		
FPL	No	3. - How many seconds of observation for “Delta F”? Does “Point C” in a. refer to “Figure 1 - Classic Frequency Excursion and Recovery” from NERC’s Survey 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

Organization	Yes or No	Question 6 Comment
		"narrow range" in item b.? 4. - Better define "relatively steady" (i.e. within a specific range and state it?) Also, "near 60.000 Hz" is not precise enough (i.e. if the event begins below 60.000 Hz, what range or time error correction is to be considered acceptable?) Is the "A" value also part of the figure cited in 3? 5. - Is the "B" value also part of the figure cited in 3? 6. - Change "should be excluded" to "will be excluded". 7. - Better explain "the cleanest 2 or 3 frequency excursion events" or remove the word "cleanest". Page 2 paragraph 5: Provide specific dates for the "quarterly postings" and where these will be posted (i.e. Internet address or other). Clarify the December 15 ERO annual post date with the dates stated for same posting on Page 3 paragraph 5 and the BA's January 10 deadline. The BA posts 30 days from which date? This is confusing. Page 2 Table 2: What of starting event frequencies that are < 60 Hz? Why is the "Highest UFLS" 59.6 when the Florida setting for its load is 59.7? Page 3 FRO equation: Page 4 of the "Frequency Response Standard Background Document, October 2011" also shows this equation but uses different terms. Make the same on both documents. In the Background Document each component of the numerator is explained and reference is made to FERC Form 714 to obtain these values. There is no reference to this form for the denominator values. All of this needs to be made clear with reference to FERC Form 714 on Attachment A.
Response: 3. Modifying event selection criteria – chart added **4 & 5 – selection criteria being modified – should provide additional clarity** **6 – modified** **7 – selection criteria being modified**		

Organization	Yes or No	Question 6 Comment
NERC is developing area to post – once developed bas will be notified **See footnote – correcting doc's -**		
Tucson Electric Power	No	Attachment A creates additional requirements to the BAL-003-1 Standard. The arrested value of frequency observed within 8 seconds may not be long enough in some instances. The delta F in the West should be greater than 0.05 Hz to ensure a measurable frequency response. West Under Frequency should be set at 59.95 Hz. There is no reliability concern for Over Frequency. Does 18 seconds after the start of the disturbance set point B? Pre-disturbance frequency should be relatively steady and near 60.000 Hz is vague. TEP feels that the ERO should not need to validate a BAs frequency bias setting.
Response: ?? **??** **Don B reviewing 59.95 - FERC desires frequency response in both ways.** **Language pt 5 vs b value** **Selection criteria modify** **Ero validating response**		
Bonneville Power Administration	No	BPA believes that Attachment A adds additional requirements to the standard.Confusion exists between Attachment A and the Background Document. Attachment A states peak load allocation is based on "Projected" Peak Loads and Generation, but the Background Document states it will use "historical" Peak Load and Generation.

Organization	Yes or No	Question 6 Comment
		3a: it may take longer than 8 seconds in some disturbances. This should be 10 seconds. .05 Hz Delta F is not low enough for the Western Interconnection, it should be .075Hz to ensure there is measurable frequency response for the interconnection. Also, under frequency should be set at 59.95 Hz. BPA does not believe there is a reliability need to include over frequency events. 3b: It is unclear if the 18 seconds is setting the B point. If this is the B point, BPA believes it should be changed to 25 seconds for the Western Interconnection. 4. Please define relatively steady and near 60 Hz. 6: For the Western Interconnection, BPA believes this needs to be 10 minutes at the top of the hour. As mid hour scheduling becomes more prevalent, the ramping at the bottom of the hour will have to be taken into account.FRO for the interconnection: Starting frequency should be the FTL limit. With RBC in place, the frequency is seldom at 60 Hz.BPA understands the theory behind setting the base obligation to the values listed in table 2. BPA would like to know if there were any studies performed to validate setting the FRO for the interconnection to such a low level?BA FRO and frequency bias setting: BPA does not agree with ERO assigning a Frequency Bias setting to each BA. This calculation is indicated as the initial FRO allocation, what is the process for changing it? BPA believes this should go through the standard drafting process for any changes. The calculation should use Peak online capacity, not the installed capacity. This would lead to the denominator being 2 X Peak projected load for the interconnection. BPA has approximately 35,000 MW of installed generation, and has never seen the actual coincidental generation go over 21,000 MW. Again, BPA doesn't believe the ERO should be validating the frequency bias setting. It is unclear to BPA how variable bias is being addressed in the standard.
Response:		
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
		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 that expected, and as a result, evaluation of fewer events will not compromise interconnection reliability. If fewer than 25 events are available in any year, the selection criteria should be adjusted to select more events.Comment 7: There are a number of problems with the use of "median" Frequency Response of the measured events. These problems make a choice other than median preferable. The following comments list some of those problems.Comment 8: The current standard uses average Frequency Response of selected events. This makes the current standard incompatible with the use of median.Comment 9: If a BA reconfigures during a measurement year, that reconfiguration will create a bi-modal distribution of the Frequency Response events. Median is incapable of representing a bi-modal distribution. The use of median will result in a standard that is incapable of measuring compliance effectively for an BA that is reconfigured during a measurement year (Dec 1 thru Nov 30).Comment 10: Any attempt to purchase additional Frequency Response from another BA for a portion of a measurement year will also cause a bi-modal distribution making the purchase of Frequency Response only effective for entire measurement years.Comment 11: Median is a non-linear measurement method. Because it is a non-linear measurement method, there is no valid way to manage partial year measurements.Comment 12: I will offer an alternative to median to the SDT before the end of the development of responses to these comments.Comment 13: The Minimum Frequency Bias Setting and the Frequency Response Obligation are both based on a method that assigns responsibility based on a Peak Load / Peak Generation share of the interconnection. However, the method used to set the Minimum Frequency Bias Setting is different than the method used to determine the Frequency Response Obligation. Using these two different methods could result in the Minimum Frequency Bias Setting being less that the FRO for a BA. The best way

Organization	Yes or No	Question 6 Comment
		to correct this problem is to use that same allocation methodology for determining the FRO and the Minimum Frequency Bias Setting. This can be easily accomplished by modifying R5 to use the FRO allocation method to determine the Minimum Frequency Bias Setting. This calculation would divide the numerator from the FRO allocation equation, divide it by two and multiply it by the percentage specified in Attachment B. In fact, the current FRS Form 1 uses this equation with projected rather than historic data. The best alternative would be to modify the R5 in the standard to match the FRO allocation method and modify FRS Form 1 to use historic data instead of projected data. This would result in only one set of Peak Load and Peak Generation data throughout the standard, rather than three different sets of data as currently written. When multiple sets of the same or similar data are used within a single standard, it only creates confusion and errors in the result.
Response:		
MRO NSRF	No	Confusion exists around the “peak load” in that Attachment A states the allocation is based on Projected Peak Loads and Generation but the Background Document states it will use a historical Peak and Generation to make the allocation. Also, for the BA installed capacity, where is that value derived from and does NERC obtain that from FERC form data or does the BA provide that information somewhere specific to this effort? Additionally, there appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same approach.If installed capacity is used in the equation, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity? Please clarify.We suggest the SDT clarify if the materials in the revised Attachment A (and Attachment B) are “Guideline” or “Technical Background”, or “requirements
Response:		
Xcel Energy	No	Confusion exists around the “peak load” in that the Attachment A states the

Organization	Yes or No	Question 6 Comment
		allocation is based on Projected Peak Loads and Generation but the Background Document states it will use a historical Peak and Generation to make the allocation. Also, for the BA installed capacity, where does that value come from and does NERC obtain that from FERC form data or does the BA provide that information somewhere specific to this effort? Additionally, there appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same approach.If installed capacity is used in the equation, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity?
Response:		
ISO/RTO Council Standards Review Committee	No	Despite the SDT's good faith effort to convert the previous Attachment A into two separate documents (Attachments A and B), the modified Attachment A is problematic. As many commenters indicated, the previous Attachment A, other than the section providing guidance on event selection, appears to be explanatory, contextual, and instructional in content. These aspects are important, but do not rise up to the level of requirements to drive reliability performance/outcome. Attachment A should include only the event selection process and calculations associated with the requirements, including an explanation of what is necessary if variable Frequency Bias Settings are implemented. If other "requirements" need to be specified, such as the reporting time frame stipulated on P. 3 of Attachment A, they should be moved to the standard itself but not imbedded in an attachment. We suggest that the SDT first determine if the materials in the revised Attachment A (and Attachment B) are "Guideline" or Technical Background", or are they "requirements". If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as-written Attachment A is a mix bag as it on the one hand describes the ERO's process for supporting the Frequency Response Standard (FRS), in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM, and on the other hand the BA's obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is

Organization	Yes or No	Question 6 Comment
		supposed to provide the technical background and guideline for another entity which is not held responsible for complying with the proposed method. Further, there are no measures provided for the requirements stipulated/imbedded in Attachment A so how can the Responsible Entity (BA, in this case) be assessed for compliance?We suggest the SDT move those requirements on the BA to the main standard, and turn Attachment A into an appendix describing the calculation process. An appendix is not regarded as a mandatory requirement. Similar comments apply to Attachment B. Moreover, if the Attachments are to be integral to the standards, the terminology “may” must be replaced with “shall”.Finally, the two Attachments are listed in Section F - Associated Documents. This Section is generally used to list reference documents that are NOT standard requirements. We suggest the SDT review and revise this listing depending on its final determination of the status of the two Attachments (or their revisions, where appropriate).
Response:		
Independent Electricity System Operator	No	Despite the SDT’s good faith effort to convert the previous Attachment A into two separate documents (Attachments A and B), the modified Attachment A is problematic. As many commenters indicated, the previous Attachment A, other than the section providing guidance on event selection, appears to be explanatory, contextual, and instructional in content. These aspects are important, but do not rise up to the level of requirements to drive reliability performance/outcome. Attachment A should include only the event selection process and calculations associated with the requirements, including an explanation of what is necessary if variable Frequency Bias Settings are implemented. If other "requirements" need to be specified, such as the reporting time frame stipulated on 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

Organization	Yes or No	Question 6 Comment
		process for supporting the Frequency Response Standard (FRS) (in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM), and on the other hand the BA's obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which, by the way, is not held responsible for complying with the proposed method. Further, there are no measures developed for the requirements stipulated/imbedded in Attachment A so how can the Responsible Entity (BA, in this case) be assessed for compliance?We suggest the SDT to move those requirements on the BA to the main standard, and turn Attachment A into an appendix describing the calculation process. An appendix is not regarded as a mandatory requirement. Similar comments apply to Attachment B.Finally, the two Attachments are listed in Section F - Associated Documents. This Section is generally used to list reference documents that are NOT standard requirements. We suggest the SDT review and revise this listing depending on its final determination of the status of the two Attachments (or their revisions, where appropriate).
Response:		
Florida Power & Light Company	No	In the table on page2 the asterick references a statement that the 59.7Hz used in Florida is a special protection scheme. This is incorrect. The special protection scheme setting was 59.82Hz and was done away with in 2005 or earlier. The 59.7Hz setting used within the FRCC is based on FRCC TWG studies that require this level of setting to protect the state in the event of a separation and to protect nuclear equipment. FPL supports the use of the C(N-2) critiera. Additionally, the reference to the FERC714 report that is currently in the background data should be made part of attachment A not separated. FPL fully agrees with Table 1The formula used to derive the FRO is inconsistant with the definition used for requirement R5. R5 states that the load is " within the BA's metered boundary". The load used in the formulae is taken from FERC714. The yearly peak demand used in R5 should be the peak monthly load from June, July or August as reported on FERC714 to be compatible

Organization	Yes or No	Question 6 Comment
		with the FRO formula.
Response:		
NV Energy	No	It is not clear whether the calculation of FRO is to utilize projections of BA load as in Att A, or past data reported in FERC Form 1 as per the Background Document.
Response:		
Los Angeles Department of Water and Power	No	LADWP considers the increase in number of events to analyze (now 25) to be excessive. Previous years analyses typically involved 4-6 events; a permanent five-fold increase is not justified. LADWP suggests reducing the baseline number of events from 25 to 12 per year. Analysis of a larger number of events could be requested on a year-by-year basis if conditions warrant, but should not be mandatory for all regions in all years.
Response:		
JEA Electric Compliance/Florida Municipal Power Agency	No	On Event Selection Criteria, bullet 2, if 25 events cannot be identified then the ERO can go back in time to the previous year. This creates a double jeopardy to R1 of the standard. It also may include irrelevant data if there have been changes from one year to the next in FRO or Bias settings assigned by the ERO.On Frequency Response Obligation, first paragraph states that "Each Interconnection will establish target contingency protection criteria"; however, the Interconnection is not a decision-making body. Does this really mean the ERO will establish FRO for each Interconnection?The single asterisk note for the table on page 2 states: "It is extremely unlikely that an event elsewhere in the Eastern Interconnection would cause the Florida UFLS special protection scheme to “false trip”.", "Special protection scheme" should be stricken from this sentence, Florida has just a regional difference in its UFLS program.

Organization	Yes or No	Question 6 Comment
Response:		
Duke Energy	No	On page 3 of the document it states “For a multiple Balancing Authority Interconnection, the Interconnection Frequency Response Obligation is allocated based upon either the Balancing Authority Peak Demand or peak generation”, however, the initial FRO allocation equation shows that the BA allocation is based upon the sum of the Projected BA Peak Load plus installed capacity, times the Interconnection FRO, and divided by the sum of the Projected Interconnection Peak Load plus Interconnection installed capacity. Is the statement in quotes correct, or is the allocation equation correct? In addition, the equation in Attachment A referencing “installed capacity” conflicts with the equation in the BAL-003-1 Background Document entitled “Frequency Response Standard Background Document” where “Peak Gen” is used. In summary, is the FRO allocation based upon an equation which a) sums the Projected BA Peak Load plus peak generation, b) sums the Projected BA Peak Load plus installed capacity, or c) uses either Projected BA Peak Load OR peak generation? All three options are currently represented in the documentation. Calculation of the FRO for the Eastern Interconnection: Duke Energy agrees with the criteria suggested for the event to be protected (4500 MW), and at this time also agrees with the “compromise” low limit of 59.6 Hz. However, knowing that another Standard is under development which may require hourly assessment of available “frequency responsive reserves”, we are trying to determine what impact the choice of this methodology will have on the amount of frequency responsive reserves the industry will have to maintain - enough to cover frequency swings that only occasionally reach down to perhaps 59.9 Hz as we see on the Interconnection today (essentially the allocated FRO for a 0.1Hz deviation), enough to cover a 4500 MW loss, or whatever we deem appropriate as long as we are compliant to the FRM? We recognize that the Standard Drafting Team cannot answer this question, as the Standard under development is not within the scope of this team, however our comment is meant to illustrate the point that similar to our response to question 8, it should be recognized that elements of this Standard are tightly coupled to other

Organization	Yes or No	Question 6 Comment
		current and potential Standards, and the impacts must be considered by the Industry.
Response:		
SERC OC Standards Review Group	No	The definition of Single Event Frequency Response Data (SEFRD) was struck from the draft standard but still appears in Attachment A. Since R1 of the standard references Attachment A, would the definition of SEFRD still be applicable? If the definition is to be totally struck, we don't think the term should be used in Attachment A.
Response:		
Hydro-Quebec TransEnergie	No	The Event Selection Criteria should be modified for the Quebec Interconnection. In Table 1, the change in frequency (Delta f) used for Quebec's Event Selection Criteria should be 0,3Hz (from point "A" to point "C") and must last for at least 7 seconds so that we don't measure AGC action. In addition, a criterion should be added by saying that events that recovered within the 20-52 second average period for point "B" should be excluded from analysis.
Response:		
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-

Organization	Yes or No	Question 6 Comment
		select only certain events, and not others, in such a way that the selected events occur evenly throughout the year, is papently wrong because it is trying to "fit" events into a process (even distribution over time) that does not govern events, but that instead governs normal operating errors that are the subject of CPM control, not of this Frequency Response standard. In other words, criteria 2 & 7 confuse Frequency Response with CPM, and events with normal operating errors. The result is a false, biased sample which destroys the integrity of this standard. Paragraph 4 on page 5 of the Background Document, on the other hand, provides a statistically correct description of event selection without sample pre-selection and should followed instead of the erroneous criteria 2 & 7 in Attachment A.
Response:		
Northeast Power Coordinating Council	No	The SDT has to first determine if the materials in the revised Attachment A & B are “Guideline” or Technical Background”, or are they “requirements”. If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as written Attachment A is confusing as it describes the ERO’s process for supporting the Frequency Response Standard (FRS) (the method and criteria it uses to calculate the frequency bias settings and the FRM), and at the same time the BA’s obligations to support this process. The latter requirements should not be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which is not held responsible for complying with the proposed method. An appendix is not regarded as a mandatory requirement.Additionally, regarding BAL-003-1- Attachment A 1. Criterion 5 needs to be re-written for clarity.2. Criterion 7 refers to “cleanest events”. A statement of what constitutes a “clean event” is needed to avoid possible controversy in the future. 3. The use of 59.6 Hz as the highest UFLS setting is flawed. It should either be 59.7 Hz as a deliberate choice to protect Florida interests, or it should be 59.5 Hz without concern for Florida’s unique settings.4. In the last 2 sentences at the end of the section on Frequency Response Obligation, it refers to an Interconnection being able to offer “alternate FRO protection criteria”. The Interconnection should have

Organization	Yes or No	Question 6 Comment
		been an integral part of establishing its obligation. It is stated that the "ERO will confirm" the "alternate FRO protection criteria". Does this mean the ERO unconditionally approves it, or evaluates with a right of rejection? Please clarify.5. In the formula for determining the Balancing Authority's FRO allocation, installed capacity is used. Does the industry have a clear and consistent definition for installed capacity? Also, with greater wind energy development, the delivered capacity over longer time horizons will be substantially less than nameplate machine ratings. The background document refers to the use of peak generation instead of installed capacity. Which shall be used? Please clarify.6. Recent studies have shown that the 18-52 second sampling interval does not work well for the Quebec Interconnection, in part due to the excellent and high level of response found in that Interconnection. The standard needs to be modified such that the sampling interval is that which works the best for each individual interconnection.7. Attachment A needs to define the point A sampling interval.
Response:		
Sacramento Municipal Utility District (SMUD)	No	The standard is unclear as to if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of Frequency Response expected on a total basis. Balancing Authorities need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet this requirement. The documents do not appear to provide any boundary on the maximum amount of Frequency Response that a BA will provide, i.e. it is not clear what will happen if an event occurs in the Eastern Interconnection that causes the 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

Organization	Yes or No	Question 6 Comment
		unclear what is expected of the Balancing Authorities.
Response:		
Western Electricity Coordinating Council	No	There is disagreement between Attachment A and the Background Document. Attachment A states peak load allocation is based on “Projected” Peak Loads and Generation, but the Background Document states it will use “historical” Peak Load and Generation.The allocation methodology of FRO among the BAs in the equation on page 3 of Attachment A favors BAs with more load than more installed capacity. Peak load is served but not all installed capacity is always dispatched.
Response:		
Alberta Electric System Operator	No	These documents not only provide additional clarity but also specify additional requirements, such as FRS Form 1 annual reporting by January 10. All the enforceable requirements should be included in the body of the standard. 1. Attachment A uses the terms "delta F (change in frequency)", "arresting frequency (Point C)", "B Value", "A Value". These terms are not properly defined or described in this document as drafted. The AESO suggests adding a description or definitions for clarity in this document. 2. The standard gives 2 sets of values for Interconnection Frequency Response Obligation in Table 2, (1) Base Obligation and (2) the obligation including 25% Safety Margin (which seems to be implied by the "contingency protection criterion"). The Attachment A does not specifiy whether the Base Obligation or the 25% Safety Margin value will be used to allocate the Interconnection FRO to the BAs. Please clarify which value will be used to calculate the BA Frequency Response Obligation (FRO) in the Interconnection FRO allocation formula in Attachment A. 3. The "initial FRO allocation" formula in Attachment A uses Peak Load. The term Peak Load is not used in the standard nor is it a defined term in the NERC Glossary. The standard uses Peak Demand, which is defined in the Glossary Is "Peak Load" synonymous with "Peak Demand"? If so, Peak Demand should be used in the formula instead. Otherwise Peak Load should be clearly defined in this document. 4. Is

Organization	Yes or No	Question 6 Comment
		"Projected" in the FRO allocation formula synonymous with "Forecasted"? If so, Forecasted should be used for consistency. Otherwise "Projected" or the context in which it appears must be defined.
Response:		
Great River Energy/ACES Power Marketing Standards Collaborators	No	Under item 3 of the Event Selection Criteria section, the delta F and Point C should be described either in this attachment or the "Frequency Response Standard Background Document". While many in industry may understand what these terms mean, history has a way of getting lost with personnel turnover. Furthermore, this would help ensure that the auditors and industry have a duplicate understanding. In the Frequency Response Obligation section on page 2, several items require more description. Further description of why an N-2 event was chosen for the Contingency Protection Criteria should be provided and which N-2 event was selected so that industry can help validate if the correct MW value was selected. Furthermore, the document should clarify if the Contingency Protection Criteria contains the "safety margin". There is a statement in the paragraph before the table that states it does but then the table lists out a separate 25% "Safety Margin". Thus, it is not clear if the "Safety Margin" is included in the Contingency Protection Criteria value listed in the table or not. "Safety margin" should be changed to "reliability margin". Safety has a specific meaning in the electric industry and its use here is not appropriate. The Base Obligation should be explained. The explanation should include its purpose and origin.
Response:		
Texas Reliability Entity	No	We have a number of concerns regarding Attachment A which are set forth below:1. Regarding the formula for "Initial FRO Allocation" on page 3 of Attachment A, the terms for "BA installed capacity" and "Interconnection installed capacity" are undefined and could be subject to manipulation and dispute. We suggest that this formula be revised to mirror the calculation based on well-established FERC Form 714

Organization	Yes or No	Question 6 Comment
		data that is discussed in the Background document, which is based on actual generation output.2. In Attachment A, all references to “Texas” should be changed to “ERCOT” as a reference to the Interconnection or the Region (including tables).3. Regarding the Event Selection Criteria in Attachment A: in item 2, consider whether certain events, such as DCS events, should be required to be included in the FRM analysis. 4. Regarding the Event Selection Criteria in Attachment A: item 7 provides that the selected frequency excursion events are to be selected so that they are evenly distributed seasonally. Consider adding the seasonal distribution concept to item 2, particularly if it becomes necessary to include events from the previous evaluation period.5. In Attachment A, page 1 says the ERO is to post the final list of frequency excursion events by December 15, but on page 3 it suggests that the list will be posted by December 10. These references should be made consistent.6. Attachment A states, on page 3, “the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year: Frequency Bias Setting and Frequency Response Obligation (FRO).” What is meant by “the upcoming year”? Is the BA supposed to implement the new FBS immediately, or wait until the beginning of the next evaluation period on December 1? Note that if the new FRO and FBS are implemented immediately (e.g. in March), then the FRO will change in the middle of an evaluation period. This will complicate the comparison of FRM and FRO as required by R1.
Response:		
Southern Company	No	We suggest increasing the delta f for the East to be the same value as the West or larger. The reason for this is that the 0.04Hz suggested is too close to the governor deadbands of .036Hz. This would potentially omit frequency response that some units may provide for a larger excursion but not for those close to the deadband.
Response:		
ISO New England Inc	No	We suggest the SDT to first determine if the materials in the revised Attachment A &

Organization	Yes or No	Question 6 Comment
		B are “Guideline” or Technical Background”, or are they “requirements”. If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as-written Attachment A is a mix bag as it on the one hand describes the ERO’s process for supporting the Frequency Response Standard (FRS), in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM, and on the other hand the BA’s obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which, by the way, is not held responsible for complying with the proposed method. An appendix is not regarded as a mandatory requirement.Additionally, BAL-003-1- Attachment A 1. Criterion 5 needs to be re-written for clarity.2. Criterion 7 refers to the “cleanest events”. Perhaps a statement of what constitutes a “clean event” is needed to avoid possible controversy in the future. 3. The use of 59.6 Hz as the highest UFLS setting seems flawed. It should either be 59.7 Hz as a deliberate choice to protect Florida interests, or, it should be 59.5 Hz without concern for Florida’s unique settings.4. In the last 2 sentences at the end of the section on Frequency Response Obligation, it refers to an Interconnection being able to offer “alternate FRO protection criteria”. It seems that the Interconnection should have been an integral part of establishing its obligation. Also, it states that the “ERO will confirm” the “alternate FRO protection criteria”. Does this mean the ERO unconditionally approves it, or evaluates with a right of rejection? Please clarify.5. In the formula for determining the Balancing Authority’s FRO allocation, installed capacity is used. Does the industry have a clear and consistent definition for installed capacity? Also, with greater wind energy development, the delivered capacity over longer time horizons will be substantially less than nameplate machine ratings. Also, the background document refers to the use of peak generation instead of installed capacity. Which shall be used? Please clarify.6. Very recent studies have shown that the 18-52 second sampling interval does not work well for the Quebec Interconnection, in part due to the excellent and high level of response found in that Interconnection. The standard needs to be modified such that

Organization	Yes or No	Question 6 Comment
		the sampling interval is that which works the best for each individual interconnection.7. Attachment A needs to define the point A sampling interval.
Response:		
Constellation Energy Commodities Group	Yes	Additional information relating to defining the FRO for the Interconnection would be helpful as would an example for calculating the BA FRO.
Response:		
American Electric Power	Yes	A frequency response observation should not be used spanning multiple years, or if there does, there should at least be a reset period.
Response:		
Cleco Corporation/ SPP Standards Review Group	Yes	We appreciate the effort of the SDT in developing Attachment A. It was very helpful in weeding through BAL-003.
Response:		
Imperial Irrigation District	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Progress Energy	Yes	
Associated Electric Cooperative Inc	Yes	

Organization	Yes or No	Question 6 Comment
South Carolina Electric and Gas	Yes	
Ameren	Yes	
Arizona Public Service Company		
ERCOT		
ReliabilityFirst		

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:

Organization	Yes or No	Question 7 Comment
Seattle City Light	Negative	Answer: Yes Comments: o LADWP and SCL note that the document "BAL-003-1 Background Document" seems to be reasonable.
Response:		
Energy Mark, Inc.	No	Comment 14: Some of the information in this document concerning the Frequency Bias Setting for BAs participating in Overlap Regulation should be moved to the Supporting Document. This change would help in addressing Comments 3 & 4 under Question 2.
Response:		
Duke Energy	No	Please see our comments to Question 6. In addition, Duke Energy disagrees with the statement on page 9 that Attachment B will "ensure there is no negative impact on other Standards" - please see our response to Question 8 for additional information.
Response:		
SERC OC Standards Review Group	No	Portions of the Background Document do not appear to be complete or finished. The Background Document should be edited to be consistent with changes made to the standard or other related documents (eg. elimination of the definition of SEFRD and any revisions to the draft BAL-003-1).
Response:		
ERCOT	No	Refer to comments in #1.

Organization	Yes or No	Question 7 Comment
Response:		
Northeast Power Coordinating Council	No	Refer to the first comment in Question 6.For the Frequency Response Standard Background Document - 1. Cite Attachment B in addition to Attachment A in the discussion of requirement R1.2. The Balancing Authority allocation method specified in this document does not agree with that in Attachment A.3. Drop the speculation on page 4 that most Balancing Authorities will be compliant. While it may be a commonly held belief by many that there is adequate frequency response right now, that assessment should be made after a targeted level of reliability has been defined and approved. The same comment applies on page 12.4. On page 6, drop the inappropriate recommendation of getting frequency response through supplemental regulation. It is inappropriate to try to substitute a “minute plus” product that is deployed centrally by the Balancing Authority for a “sub-minute” product that is deployed automatically without any Balancing Authority action. When a pseudo-tie is used, changes in the ACE values due to supplemental regulation are unrelated to and not coordinated with the need to deploy frequency response. Not only should this approach not be offered as an alternative, but the FRSDT should actively conduct research to determine if supplemental regulation via a pseudo-tie should be deliberately REMOVED from any actual net interchange calculation that may include it. This comment also applies to the mentioning of supplemental regulation on page 11 as well.5. On page 7, the reference to a 24 hour window on each side of the frequency bias setting implementation date is inconsistent with the wording of the standard. The standard states that any time within the designated date is acceptable.6. On page 8, the inclusion of “for training purposes” as a reason to not operate in tie line bias control should be dropped. This training can be done in a training simulator. If it is determined that it should be supported, then the requirement needs to be reworded to allow it explicitly. 7. On page 14, the sentence: “This approach would only provide feedback for performance during that specific event and would not provide insight into the depth of response or other limitations” is difficult to understand. The paragraph would read better by simply deleting the

Organization	Yes or No	Question 7 Comment
		sentence.
Response:		
Xcel Energy	No	Same comment here as the one in question 6.
Response:		
ISO New England Inc	No	See first comment in 6 above. Also, Frequency Response Standard Background Document - 1. Cite Attachment B in addition to Attachment A in the discussion of requirement 1.2. The Balancing Authority allocation method specified in this document does not agree with that in Attachment A.3. Drop the speculation on page 4 that most Balancing Authorities will be compliant. While it may be a commonly held belief by many that there is adequate frequency response right now, that assessment should be made after a targeted level of reliability has been defined and approved. The same comment applies on page 12.4. On page 6, drop the inappropriate recommendation of getting frequency response through supplemental regulation. It is inappropriate to try to substitute a “minute plus” product that is deployed centrally by the Balancing Authority for a “sub-minute” product that is deployed automatically without any Balancing Authority action. When a pseudo-tie is used, changes in the ACE values due to supplemental regulation are unrelated to and not coordinated with the need to deploy frequency response. Not only should this approach not be offered as an alternative, but the FRSDT should actively conduct research to determine if supplemental regulation via a pseudo-tie should be deliberately REMOVED from any actual net interchange calculation that may include it! This comment also applies to the mentioning of supplemental regulation on page 11 as well.5. On page 7, the reference to a 24 hour window on each side of the frequency bias setting implementation date is inconsistent with the wording of the requirement. The requirement says that any time within the designated date is acceptable.6. On page 8, the inclusion of “for training purposes” as a reason to not operate in tie line bias control should be dropped. This sort of training can be done in

Organization	Yes or No	Question 7 Comment
		a training simulator. Alternatively, if it is determined that it should be supported, then the requirement needs to be reworded to allow it explicitly. 7. On page 14, the sentence: “This approach would only provide feedback for performance during that specific event and would not provide insight into the depth of response or other limitations” is difficult to understand. The paragraph would read better by simply dropping it.
Response:		
Western Electricity Coordinating Council	No	See response to question 6.
Response:		
Alberta Electric System Operator	No	The Background Document uses BA Peak Generation in the BA FRO allocation formula. Attachment A uses BA Installed Capacity. The AESO suggests making the two formulae consistent.
Response:		
Florida Municipal Power Agency	No	The document does not discuss how the new reliability parameter will affect BAs
Response:		
JEA Electric Compliance	No	The document does not discuss how the new reliability parameter will affect BAs
Response:		
MRO NSRF	No	the MRO NSRF has restated the same answer as in question 6 on purpose. Confusion exists around the “peak load” in that Attachment A states the allocation is based on Projected Peak Loads and Generation but the Background Document states it will use

Organization	Yes or No	Question 7 Comment
		a historical Peak and Generation to make the allocation. Also, for the BA installed capacity, where is that value derived from and does NERC obtain that from FERC form data or does the BA provide that information somewhere specific to this effort? Additionally, there appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same approach.If installed capacity is used in the equation, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity? Please clarify.Page 7 (3rd paragraph) of the Background document states “Given the fact that BA’s can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date.1) The Standard itself does not state this provision (24 hour window on each side of target date) as indicated. 2) The SDT accurately addresses the fact that BA’s could have EMS or staffing issues during implementation of the ERO validated FBS. The current stated 72-hour window is not long enough for implementation of the FBS as there may be a host of issues that could impact implementation. We suggest that a seven day window be used for implementation of the FBS.
Response:		
Texas Reliability Entity	No	There is an inconsistency between the Background Document and Attachment A. Attachment A only proposes event criteria based on “the largest category C (N-2) event identified,” but the Background Document says: “Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection’s Frequency Response Obligation: - Largest category C loss-of-resource (N-2) event; - Largest total generating plant with common voltage switchyard; - Largest loss of generation in the interconnection in the last 10 years.”
Response:		
Great River Energy/ACES	No	We can find no document titled “BAL-003-1 Background Document”. We assume this

Organization	Yes or No	Question 7 Comment
Power Marketing Standards Collaborators		question is referring to the “Frequency Response Standard Background Document” dated October 2011. We do not believe the document provides sufficient clarity. No explanation is provided for why RSG was added to Requirement R1.There are typos contained in the document. On page 6 in NIA, the A should be in subscript. On page 7 in bullet 4 in the first sentence, “The” should be in lowercase
Response:		
Southern Company	No	We suggest the Background Document should be edited to be consistent with changes made to the standard or other related documents (eg. Any revisions to draft BAL-003-1 and removal of the definition of SEFRD).
Response:		
Seattle City Light	Yes	o LADWP and SCL note that the document “BAL-003-1 Background Document” seems to be reasonable.
Response:		
Constellation Energy Commodities Group	Yes	Should be revisited based on the propposed modifications to the requirements.
Response:		
Los Angeles Department of Water and Power	Yes	LADWP notes that the document “BAL-003-1 Background Document” seems to be reasonable.
Response:		
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

Organization	Yes or No	Question 7 Comment
		determining FRM, that the Background Document mentions in paragraph 4 of page 4 is being evaluated by the drafting team for application in this standard, should be considered for deployment as soon as possible to replace the administered method currently proposed in this standard, because the administered method lacks any technical justification. No such justification was ever attempted in the development of this standard. The administrative method of determining FRM is therefore but a highly dubious "quick fix" until the risk-based method is evaluated and implemented. The administrative method is in fact perverse because it discourages BAs from reducing their contribution to frequency error by refusing to reduce the BA's FRO accordingly, and because it encourages BAs to contribute to frequency error without increasing their FRO.
Response:		
Manitoba Hydro	Yes	Please see MH's response to Question 1 regarding the term Single Event Frequency Response Data. Additionally, the discussion in this document is useful in clarifying the intent of the drafting team, but some of this clarification would best be incorporated into the Standard itself. Ex. RSG requirement on page 6. Also on page 7 Attachment A does not specify what validation is and how it is done. Attachment A refers to BA providing FBS data to ERO which then validates and publishes. This should be reflected in R2.
Response:		
NV Energy	Yes	This is a good reference; however see response to Question 6 in that there appears to be a discprepancy between Att A and the Background Document with regard to FRO calculation.
Response:		
Cleco Corporation/SPP	Yes	We appreciate the effort of the SDT in developing the Background Document. It

Organization	Yes or No	Question 7 Comment
Standards Review Group		provided insight on how the SDT got the proposed standard to where it is with this posting.
Response:		
Imperial Irrigation District	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Progress Energy	Yes	
Florida Power & Light Company	Yes	
FPL	Yes	
FMPP	Yes	
Tucson Electric Power	Yes	
Associated Electric Cooperative Inc	Yes	
South Carolina Electric and Gas	Yes	
Ameren	Yes	

Organization	Yes or No	Question 7 Comment
Hydro-Quebec TransEnergie	Yes	
ISO/RTO Council Standards Review Committee/ Independent Electricity System Operator		We do not have an opinion on whether or not the Background Document provides sufficient clarity to the development of the standard. We do, however, suggest that the SDT consider our comments in Q6, above, and move some of the information from Attachments A and B to or combine with the Background Document, to the Background Document to provide all the technical basis and background behind the elements stipulated in the requirements.
Response:		
Bonneville Power Administration		
Sacramento Municipal Utility District (SMUD)		
Arizona Public Service Company		
American Electric Power		
ReliabilityFirst		

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:

Organization	Yes or No	Question 8 Comment
Seattle City Light	Negative	Answer: Yes Comments: o LADWP and SCL note that Attachment B seems to be reasonable.
Response:		
Constellation Energy Commodities Group	No	Should be revisited based on the proposed modifications to the requirements.
Response:		
MRO NSRF	No	: There could be some confusion caused by the Attachment B due to the use of the word “initially” when the reference is made to the current standard. The drafting team should change the word “initially” to “currently” or strike it to avoid the potential confusion.The second paragraph of Attachment B (which contains the two bullets):The words “initially 1%” in the second bullet contradict with the Table 1 on Attachment B, which states “Initial” and “0.8%”. Suggest deleting the parenthetical in the second bullet as when BAL-003-1 is effective it would be referencing an old Standard version. If the initial minimum is intended to be 1% say so in the Table 1.
Response:		
Texas Reliability Entity	No	1. In Attachment B, we suggest removing the paragraph beginning “The BA calculates . . .” because it appears to be background information that conflicts with the methods provided in this version of the standard for determining minimum bias settings.2. 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?

Organization	Yes or No	Question 8 Comment
Response:		
Bonneville Power Administration	No	BPA understands the concept and we disagree with it. As the ERO continues to lower the required minimum frequency bias setting for an interconnection, the BA's that have frequency response higher than the 1% will have a higher percentage of the frequency response of the interconnection. Also, this standard is primarily measuring AGC response, not natural frequency response; therefore not lowering the limit is appropriate.
Response:		
Duke Energy	No	Duke Energy suggests that the SDT consider a term other than "Initial' in the title for Table 1. We suggest "Proposed Frequency Bias Setting" for Table 1. Notwithstanding our suggestion that the criteria/requirements of the minimum FBS in the Attachment be incorporated into the Standard, Duke Energy has the following concerns with what is proposed:As cited in our comments to Question 8 in the last posting (extensive, so not repeated here), the secondary control measures of CPS1, CPS2 and the draft Balancing Authority ACE Limit (BAAL) are tightly coupled to the Frequency Bias Setting (FBS), and a reduction of the FBS will impact the secondary control requirements placed upon the BA. Noted in our response to Question 7 above, the statement on page 9 in the "BAL-003-1 Background Document"is not correct in stating that Attachment B will "ensure there is no negative impact on other Standards".The gradual reduction of the FBS will proportionally tighten the secondary control limits for each Balancing Authority. Even if the "natural" Frequency Response in the Eastern Interconnection remains unchanged for the next several years, under the process described allowing the ERO to annually adjust the minimum FBS for the Interconnection, the FBS will eventually be reduced to a value approximately 10% above the calculated response in magnitude, cutting the current CPS1, CPS2 and BAAL limits in the Eastern Interconnection on average by more than half. The current FBS for the Eastern Interconnection is approximately minus 6500 MW/0.1Hz,

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

Organization	Yes or No	Question 8 Comment
Response:		
Sacramento Municipal Utility District (SMUD)	No	In addition to the requirements, reducing frequency bias obligation results in generation tripping closer to the set point. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.
Response:		
NV Energy	No	In Attachment B, it seems unclear whether the initial FB setting is supposed to be 1% of BA peak load or 0.8% as shown in the table. In general, I was extremely confused about what the required FB setting should be. R5 indicates a percentage of load found in Att B, but Att B indicates the greater of Natural Frequency Response or 1% of peak, and then the table that follows indicates 0.8%. At this point, I have no idea what is being stated for the requirement.
Response:		
Progress Energy	No	PGN supports the collective comments of SERC members. We suggest the SDT consider a term other than "Initial' in the title for Table 1. We suggest "Proposed Frequency Bias Setting" for Table 1
Response:		
Independent Electricity System Operator	No	Please see our comments under Q6. In brief, we do not agree with including a process description type of document as part of the standard requirement.
Response:		
ISO/RTO Council Standards	No	Please see our comments under Q6. In brief, we do not agree with including a

Organization	Yes or No	Question 8 Comment
Review Committee		process description type of document as part of the standard requirement. Process description should be regarded guideline document and not a part of the standard requirement.
Response:		
Tucson Electric Power	No	Reducing a BAs frequency bias setting may have an adverse impact on recovering from a frequency event once you get past the first 8-10 seconds. A larger bias will allow for actual and sustained AGC generator responses. Industry focus should be on generator governor response within the first 8-10 seconds.
Response:		
Northeast Power Coordinating Council	No	Refer to the first comment in Question 6.
Response:		
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 mandate us to have a larger Bias that what is really needed. Unlike Eastern Interconnection, we are not over biased. By implementing this new methodology, it would make us over biased. Having a too large Bias could lead to system instability, based on the results of studies from our control specialists. The Minimum Frequency Bias Setting should take into account the wide load span that we can face. For the variable bias, we could express the Minimum Frequency Bias Setting as a function of monthly peak loads, and remove the Natural Frequency Response term. In addition,

Organization	Yes or No	Question 8 Comment
		there is a gap between Attachment B and the text in R5. See comment 10 for explanation.
Response:		
Xcel Energy	No	There could be some confusion caused by the Attachment B due to the use of the word “initially” when the reference is made to the current standard. The drafting team should change the word “initially” to “currently” or strike it to avoid the potential confusion.
Response:		
Florida Power & Light Company	No	There is no technical justification provided either in the attachment or background data for the initial starting value of 0.8%. This is acceptable but is arbitary. Additionally, the last sentense on page 1 of Attachment B should be changed to read " the ERO must reduce (in absolute value) the minimum Frequency Bias Settings for BA's within that Interconnection, by 0.1 percentage point from its previous annual value, to better match the Frequency Bias Setting to the natural Frequency Response or provide technical justification for not implementing the reduction
Response:		
SERC OC Standards Review Group	No	We suggest the SDT consider a term other than “Initial’ in the title for Table 1. We suggest “Proposed Frequency Bias Setting” for Table 1
Response:		
South Carolina Electric and Gas	No	We suggest the SDT consider a term other than “Initial’ in the title for Table 1. We suggest “Proposed Frequency Bias Setting” for Table 1
Response:		

Organization	Yes or No	Question 8 Comment
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.
Response:		
Southern Company	No	We suggest using the words, 'Proposed Frequency Bias Setting' in the Title of Table 1 instead of the word, 'Initial'.
Response:		
ERCOT	No	While there is no problem with the calculation involved, it is unclear why the SDT elected to assign a grid performance element in this standard to the ERO, who has no functional (registered) role in grid performance. Since this is a cook-book calculation and transfer of data on frequency performance, why not assign it to the BA?
Response:		
Seattle City Light	Yes	o LADWP and SCL note that Attachment B seems to be reasonable.
Response:		
Energy Mark, Inc.	Yes	Comment 15: This Yes answer assumes that the SDT addresses Comment 13 under

Organization	Yes or No	Question 8 Comment
		Question 6 in these comments.
Response:		
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.
Response:		
Los Angeles Department of Water and Power	Yes	LADWP notes that Attachment B seems to be reasonable
Response:		
FPL	Yes	Last paragraph: As stated, would that make the Minimum Frequency Bias Setting 0.7% of peak load or generation? A numerical example shown would help clarify this paragraph.
Response:		
Southwest Power Pool Regional Entity	Yes	Need to clarify that 2012 Bias setting will be based on 1% of peak load or generation until approval of BAL-003-1 by FERC establishing the .08% of peak load or generation minimum threshold.
Response:		
Associated Electric	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

Organization	Yes or No	Question 8 Comment
Cooperative Inc		that, upon going into effect, this BAL-003-1 will utilize these initial settings.
Response:		
Imperial Irrigation District	Yes	
SPP Standards Review Group	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Salt River Project	Yes	
FMPP	Yes	
American Electric Power	Yes	
Cleco Corporation	Yes	
Manitoba Hydro	Yes	
Great River Energy	Yes	
Keen Resources Asia Ltd.	Yes	
Western Electricity Coordinating Council		
Florida Municipal Power Agency		
JEA Electric Compliance		

Organization	Yes or No	Question 8 Comment
Arizona Public Service Company		
Alberta Electric System Operator		
ReliabilityFirst		

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:

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)-

Organization	Yes or No	Question 9 Comment
		and requests that all spreadsheets and calculation tools developed under 2007-12 be revised to support common software of the past 10 years.
Response:		
Seattle City Light	No	o LADWP and SCL note that Form 2 is not compatible with prior versions of Excel-it won't even open in Excel 2003 (which is still widely used)-and requests that all spreadsheets and calculation tools developed under 2007-12 be revised to support common software of the past 10 years.
Response:		
Associated Electric Cooperative Inc	No	AECI believes the SDT could spare our industry both confusion and inconsistency, by specifying that identified Interconnection Disturbances include both Point A and Point B to the hour, minute, and second. While this introduces some risk of Entities over-automating their data-reports, the benefits for Eastern Interconnection respondents would be tremendous. Cautions and disclaimers should be placed on both Form 1 and Form 2, to assure respondents manually inspect their frequency data and pinpoint the specific inflection-point samples.
Response:		
Bonneville Power Administration	No	BPA believes the form is not easily understood and is overly complicated for what it is trying to accomplish. BPA believes the form might work for an internal evaluation, just not for an external audit. Compliance is based on this form. BPA believes the standard needs to be simplified and possibly returned to a data gathering standard.
Response:		
FPL	No	FRS Form 2 - Two-second Sample DataInstructions tab/worksheet: What is referred to as or meant by the 'master event list'?4. - Regarding 2 second sample rate for 25

Organization	Yes or No	Question 9 Comment
		minutes starting 2 minutes before event begins and 15 minutes after it begins, does this add up to 25 minutes or are additional minutes being required for collection? Also, FPL can report frequency at this rate, but can only report load in MW every four seconds. Move to 4 second sample rate.6-8. - Possible to add button to auto-populate cells C8 and C11 in 'Entry Data' tab from the new column C and cell identifying the desired frequency change time and simplify these steps?10. - Clarify where the "Copy" button is. Is it the one in the 'Data' tab or worksheet?Entry Data tab/worksheet:Step 6 should also be or be moved to the "Instructions" worksheet.Are the values in column C in the "Data" worksheet labeled "Total Lost Generation" the same as those in column AQ in the "Evaluation" worksheet? If so, why are they not both labeled "Net Actual Interchange"?What is the definition of "Non Conforming Load" in column E?
Response:		
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 the Comment Form asking whether the additional information should be requested. We believe this is a significant change to the standard and many commenters may have missed the opportunity to comment on it. Compared to the previous version, Form 1 has been significantly expanded to include not only additional sheets but much more comprehensive data requirements even on the Data Entry sheet itself. This makes data submission a very time-consuming task but the justification for requiring detailed data entry has not been provided. We question the need for such expansion on data entry requirements. We have yet to see the reason for expanding Form 1 in assisting a BA to provide the data needed to comply with the standard, hence we do not see how adding a Form 2 can help in that regard. We suggest the SDT to keep data requirements to only what is minimally needed to support the FRS reporting process. Where the SDT deems additional data entry sheets to be necessary, it should provide the rationale for expanding from a 2 sheet form into a

Organization	Yes or No	Question 9 Comment
		multiple sheet form for additional data collection. Where the SDT deems the additional data sheet or information not necessary to support FRS reporting, then we suggest the SDT to hide those pages not required for the standard so as to avoid confusion, and/or to remove those analytical pages not directly used in the standard.
Response:		
Independent Electricity System Operator	No	If we are not mistaken, Form 2 is added as the last sheet in the Form 1 spreadsheet file. Apart from that, however, there are other sheets added to the previous Form 1. But this Comment form makes no mention of the changes, nor is there a question on the additional information requested. We have a concern over this omission of attention or oversight. Compared to the previous version, Form 1 has been significantly expanded to include not only additional sheets but much more comprehensive data requirements even on the Data Entry sheet itself. This makes data submission a very time-consuming task but the justification for requiring detailed data entry has not been provided. We question the need for such expansion on data entry requirements. We have yet to see the reason for expanding Form 1 in assisting a BA to provide the data needed to comply with the standard, hence we do not see how adding a Form 2 can help in that regard. We suggest the SDT to look at the basic need for data submission that would suffice to support the FRS reporting process. Where the SDT deems additional data entry sheets to be necessary, it should provide the rationale for expanding from a 2 sheet form into a multiple sheet form for additional data collection.
Response:		
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.

Organization	Yes or No	Question 9 Comment
Response:		
Tucson Electric Power	No	TEP feels that Form 2 is a useful tool for internal BA use and should not be used for compliance purposes.
Response:		
MRO NSRF	Yes	: It would be useful if the drafting team could develop a completed form as an example to help entities better understand the methodologies used in the form
Response:		
Xcel Energy	Yes	It would be useful if the drafting team could develop a completed form as an example to help entities better understand the methodologies used in the form.
Response:		
Ameren	Yes	We agree that the spreadsheet is meaningful, but still needs to be vetted through the field trial process, with improvements made based on experience in its use.
Response:		
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	
Western Electricity Coordinating Council		
Florida Municipal Power Agency		
JEA Electric Compliance		
ACES Power Marketing Standards Collaborators		
Sacramento Municipal Utility District (SMUD)		
Arizona Public Service Company		
ERCOT		
Texas Reliability Entity		
Alberta Electric System Operator		

Organization	Yes or No	Question 9 Comment
ReliabilityFirst		

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:

Organization	Yes or No	Question 10 Comment
Muscatine Power & Water	Negative	"MPW agrees with the comments submitted by the MRO-NSRF."
Response: MRO response		

Organization	Yes or No	Question 10 Comment
FirstEnergy Corp.; FirstEnergy Energy Delivery; FirstEnergy Solutions;Ohio Edison Company	Abstain	FirstEnergy appreciates the hard work of the drafting team but needs more time to review the standard with internal business units and with our RTO. Therefore at this time we must abstain.
Response: thanks		
	Abstain	As a qualified professional statistician I abstain from voting "affirmative" or "negative" on this standard because it violates two fundamental statistical best practices. 1. In the Standard, the definition of Frequency Response Measure (FRM) is statistically wrong. The median is an improper statistical measure of Frequency Response because --it truncates large excursions which are the specific subject of Frequency Response control, not normal operating frequency errors which are self-correcting and are the subject of CPM control; --it is non-linear; --it is non-summable over the interconnection; in other words, the individual BA medians don't add up to the interconnection median, in complete incompatibility with CPM control which requires summability of BA performances into the interconnection's performance. Moreover, it is mathematically impossible to sum the medians of the BAs in a Reserve Sharing Group (RSG) into the RSG's median: in other words, the RSG's median cannot represent the sum of the medians of its members. The last paragraph on page 5 of the Background Document is patently wrong, invented, and supported in no probability & statistics literature whatsoever. As a practicing statistician, I hereby give testimony to the utter falsehood of the statement that "In general, statisticisns use the median as the best measure of central tendency when a population has outliers." (See http://www.robertblohm.com/BestStatistic.doc for an explanation of "best statistic" which is a highly technical and central topic in modern probability theory and statistics.) Also, "outliers" are falsely and rhetorically claimed to be "noise" when in fact they are the "events" that are the specific subject of Frequency Response. It is well known that they do not "fit" a normal distribution.

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

Organization	Yes or No	Question 10 Comment
		because the administered method lacks any technical justification. No such justification was ever attempted in the development of this standard. The administrative method of determining FRM is therefore but a highly dubious "quick fix" until the risk-based method is evaluated and implemented. The administrative method is in fact perverse because it discourages BAs from reducing their contribution to frequency error by refusing to reduce the BA's FRO accordingly, and because it encourages BAs to contribute to frequency error without increasing their FRO.
Response: determination of FRM response		
Associated Electric Cooperative, Inc.	Affirmative	Please see comments submitted by John Bussman of AECI. Thanks, Chris Bolick
Response: AECI response		
City Utilities of Springfield, Missouri	Affirmative	SPRM supports the comments from SPP.
Response: SPP response		
Electric Reliability Council of Texas, Inc.	Affirmative	Please refer to the comments submitted by ERCOT under the posting. Thank you.
Response: ERCOT response		
Midwest ISO, Inc.	Affirmative	We would like to thank the drafting team for developing a standard responsive to the FERC Orders.
Response: thanks		

Organization	Yes or No	Question 10 Comment
Oklahoma Gas and Electric Co.	Affirmative	See comments submitted by the Southwest Power Pool
Response: SPP response		
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.
Response: look at closer later		
SERC Reliability Corporation	Affirmative	Please see comments submitted by the SERC Operating Committee standards subgroup for technical suggestions to improve the standard.
Response: SERC OC		
Tennessee Valley Authority	Affirmative	Comments submitted by SERC OC Standards Review Group. TVA votes affirmative with comments previously submitted by SERC.
Response:		
AEP, AEP Marketing, AEP Service Corp.	Negative	AEP's negative ballot is primarily due to our concerns regarding R1. Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Response:		

Organization	Yes or No	Question 10 Comment
Alberta Electric System Operator	Negative	Please see the AESO comments submitted during the Formal Comment Period.
Response:		
Ameren Energy Marketing Co.; Ameren Services	Negative	We believe that this is good start to a worthwhile standard, but the following issues need to be addressed in this standard: (1) The FRM methodology has not been fully vetted through the field trial process. (2)Adjusting the minimum of the Frequency Bias Setting, while an appropriate adjustment for AGC control in the ACE equation, should not be at the expense of L10 as used in BAL-001, R2. (3) The absence of any resource specific frequency response requirement in NERC standards is an issue that must be address somewhere. As the resource portfolio of our industry changes(expedited by recent EPA rulemaking), the resources used for traditional primary frequency response are becoming a lower percentage of the mix. New resources and existing resources that have not provided primary frequency response need to be incorporated into the available frequency response discussion. (4) BAL-003 is only applicable for an interconnected system, conditions that are created by islanding and other emergences are not address here(nor should they), but need to be address within the EOP family of standards, so that adequate primary frequency response is available during emergency situations.
Response: (1) – **(2) – That is why reduction is being done slowly – being monitored closely (FBS issue Terry B, etal)** **(3) – assigning to generators group** **(4) – NERC Issues**		
Atlantic City Electric Company	Negative	See comments submitted by David Thorne in Segment 1, Potomac Electric Power

Organization	Yes or No	Question 10 Comment
		Company
Response:		
Avista Corp.	Negative	This standard should be designed for each interconnection explicitly rather than one size fits all. Frequency is an interconnection issue and response is driven by the interconnection's topology. One size does not fit all for interconnections. This standard should be designed around the explicit needs of each interconnection. Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.
Response: an interconnection has the capability to request a variance (especially one that is more restrictive) **Minimum lowering response**		
Beaches Energy Services; City of Bartow, Florida; Tampa Electric Co.	Negative	We thank the SDT for their hard work and diligence in moving this Project forward. However, I have some concerns that cause me to not support the standard in its current form. In general, I believe that there has not been sufficient prudency review for the standard, especially R1, to justify a performance based standard around a Frequency Response Measure. I also believe that the proposed standard does not meet the intent of the Final SAR or Supplemental SAR. The “Final SAR” was to develop methods by which a performance based standard would eventually be developed. The Final SAR states: “The proposed standard’s intent is to collect data needed to accurately model existing Frequency Response. There is evidence of continuing decline in Frequency Response in the three Interconnections over the past 10 years, but no confirmed reason for the apparent decline. The proposed standard requires entities to provide data so that Frequency Response in each of the Interconnections can be modeled, and the reasons for the decline in Frequency Response can be identified. Once the reasons for the decline in Frequency Response

Organization	Yes or No	Question 10 Comment
		are confirmed, requirements can be written to control Frequency Response to within defined reliability parameters." BAL-003-1 is beyond the scope of this "Final SAR". For instance, "the reasons for the decline in Frequency Response" were not confirmed to our knowledge; and the field trial is not completed to our knowledge. The Supplemental SAR adds to the scope of the Final SAR: "To provide a minimum Frequency Response Obligation for the Balancing Authority to achieve, methods to obtain Frequency Response and provide a consistent method for calculating the Frequency Bias Setting for a Balancing Authority. In addition, the standard will specify the optimal periodicity of Frequency Response surveys." Please note that the Standards Development Roadmap does not confirm whether this Supplemental SAR was ever approved; hence, I question whether this is actually part of the scope of the SDT. Be that as it may, the Supplemental SAR does not eliminate the pre-requisite contained in the Final SAR to determine the reasons for the decline in frequency response and confirm them before establishing "defined reliability parameters". In addition, the standard does not meet the scope requirements of the Supplemental SAR.
Response: 693 – March 2010 Order – **Look at SAR – original sar prior to 693 – 693 trumps original sar (SC October 2010 meeting)**		
Constellation Energy Commodities Group	Negative	Please see submitted comments for additional detail behind the negative vote.
Response:		
Energy Mark, Inc.	Negative	The issue of Median, Mean, Regression needs to be resolved using Field Trial data. This should be able to be completed before the end of January 2012. The FRO and Minimum Bias Setting allocations should be determined using a single allocation method and a single data set. Wording changes are needed in the Requirements to indicate compliance in all cases for all BAs. In general, although this standard has many weaknesses, its implementation with small modifications will be better than

Organization	Yes or No	Question 10 Comment
		failure to implement it.
Response: sdt working on this		
Energy Mark, Inc.	Negative	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 be taken before Real Time as Operations Assessment.
Response: req does not fall into a single category – the operator is constantly taking actions some of which were set in "longer term" horizon, some in real-time and this is an after-the-fact measure.		
Fort Pierce Utilities Authority	Negative	FPUA supports the comments submitted by Florida Municpal Power Agency (FMPA) through the formal comment process.
Response:		
Hydro One Networks, Inc.	Negative	Hydro One is casting a negative vote for this project. We support and subscribe to the comments submitted by NPCC on behalf of its members. In summary, the comments are: 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. o Use of installed capacity in determining the Frequency Response Obligation. o The sampling interval should be tuned on a per Interconnection basis to support

Organization	Yes or No	Question 10 Comment
		HQTE's characteristics. o NPCC does not advocate the use of supplemental regulation as a method of procuring frequency response. 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 discretional frequency response are generators. 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. o In the formula for determining the Balancing Authority's FRO allocation, installed capacity is used. Is there a clear and consistent definition for installed capacity? Considering the growth of wind energy development, the delivered energy from wind generation over longer time horizons will be substantially less than the machine nameplate ratings. o The background document refers to the use of peak generation instead of installed capacity. Which shall be used? o Additional minor issues for the SDT consideration that should be addressed: ? A link should be provided in the standard to FRS Form 1, or instructions provided for how entities may find the form. ? In the definitions, FRS should be spelled out before using the acronym.
Response: make sure issues are covered earlier **1 - ??** **2 - ??** **3 – modified event selection criteria to satisfy concern**		

Organization	Yes or No	Question 10 Comment
4 – rsg response 5 – generator response 6 – agree but typo in statement? 7 – inconsistency has been resolved 8 – resolved Addt'l Will be a link Frs spelled out		
Independent Electricity System Operator	Negative	The complete IESO's comments on the revised standard are provided through the electronic comment form. The summary below highlights IESO's major concerns with the revised standard: 1)The definition for Frequency Response Measure (FRM): The proposed FRM definition: "The median of all the Frequency Response observations reported annually on FRS Form 1" is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an attachment to the standard. In the current NERC Glossary of Terms, there is no such precedence that a definition must rely on the requirements or details in a standard for completeness. Also, it is very cumbersome that when changes are made to FRS Form 1, the definition must be posted for industry comment and balloting, and vice versa. When other standards begin using the term, there will be cross references between standards. This further complicates the update/maintenance problem without any appreciable value. (See complete comment in Section Q1 in the electronic comment form) 2)Attachment A: Attachment A should include only the event selection process and calculations associated with the requirements, including an explanation of what is necessary if variable Frequency Bias Settings are implemented. If other "requirements" need to be specified, such as the reporting time frame stipulated on

Organization	Yes or No	Question 10 Comment
		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) 3)The expanded FRS Form 1 and the addition of a Form 2 ask for data entry that is excessive and whose value has not been demonstrated. (See complete comment in Section Q9 in the electronic comment form)
Response: 1) ??? & nerc process (look at Q1) **2) reporting req's should not be a req (Q6)** **3) this version is not asking for any additional information than that which is presently being used – the extra input values (adj) are optional – previous comments asked for ability to input this data (see Q9)**		
ISO New England, Inc.	Negative	Please refer to our comments submitted on this project.
Response:		
JDRJC Associates	Negative	Support Midwest ISO Comments
Response:		
JEA	Negative	JEA is not comfortable with a performance based standard as written without more field testing to ensure that net interchange is not skewed by load and generation changes that are not a function of frequency. Since frequency response has components from load and generation resources, and load is not controllable for the most part, seems this standard should be directed at specific generator response methods from the GO/GOP's. This is a wide reaching standard. And, this is a performance standard (if it doesn't perform as designed, it is a violation). Because of this, more testing needs to be completed so we know the model is correct. We are not sure we know how to

Organization	Yes or No	Question 10 Comment
		ensure compliance. Don't agree the standard needs to be performance based.
Response: field trial still going - other tech to provide response **order 693 -**		
Kansas City Power & Light Co.	Negative	The proposed Standard BAL-003-1 does not consider the real time operating conditions under which this standard should apply. There are no considerations for the complexities introduced by capacity energy agreements between BA's nor consideration of the differing level of Interconnection Frequency Response needed at times of minimum interconnection load conditions and interconnection peak load conditions.
Response: howard to respond		
Lakeland Electric	Negative	In general; here has not been sufficient prudency review for the standard, especially R1, to justify a performance based standard around a Frequency Response Measure. Refer to comments submitted by FMPA on LAK behalf.
Response: FMPA response		
Liberty Electric Power LLC	Negative	Voting no due to SDT addressing FERC directives with attachments instead of in the standard requirements.
Response: NERC attachment response		
Lincoln Electric System	Negative	Please see comments submitted by the MRO NSRF. (See comments for Question 5 submitted by the MRO NSRF.)
Response: mro response		

Organization	Yes or No	Question 10 Comment
Louisville Gas and Electric Co.	Negative	We support the comments in the SERC OC Standards Review Group Comments.
Response: serc oc response		
Madison Gas and Electric Co.	Negative	Please see the MRO NSRF comments
Response: mro response		
Manitoba Hydro	Negative	Please see comment form submitted by Manitoba Hydro.
Response: Manitoba hydro response		
Midwest Reliability Organization	Negative	Please see the comments submitted by MRO NSRF. As MRO Sector 10 we agree with MRO NSRF position and recommendation to vote negative for this ballot.
Response: mro nsrf response		
Muscatine Power & Water	Negative	"MPW agrees with the comments submitted by the MRO-NSRF."
Response: mro nsrf resaponse		
Nebraska Public Power District	Negative	NPPD joins it's comments with comments submitted by the Midwest Reliability Organization - NERC Standards Review Forum (MRO NSRF) submitted on December 8, 2011.
Response: mro response		
New Brunswick Power Transmission Corporation	Negative	The compliance burden should not fall on the BA as the provider of Frequency Response (i.e. Primary Control response). In this case the BA per se has no assets, moreover the primary response service providers have no obligations to provide the service, thus the BA potentially could face a situation where there is no physical service to be purchased but there is a mandated standard to comply with. The idea

Organization	Yes or No	Question 10 Comment
		of creating a Primary Response Market as some have proposed does not work without an obligation on some entity to physically provide that service.
Response: functional model response -		
New Brunswick System Operator	Negative	Please see comments submitted by the NPCC Reliability Standards Committee and the IRC Standards Review Committee
Response: npcc response		
New York Independent System Operator	Negative	The NYISO's comments are included with both the Joint IRC/SRC and Joint NPCC RSC comments.
Response: npcc rsc response		
New York State Department of Public Service, National Association of Regulatory Utility Commissioners	Negative	After review of the standard and draft comments to be submitted by industry participants, it appears that there are many areas of the proposed standard that require clarification.
Response: thanks for participation		
Northeast Power Coordinating Council	Negative	NPCC will be submitting some comments during the comment period of the standard and will not repeat those comments here. NPCC believes some revisions to the standard need to be made therefore will not support the VSLs at this time. Comments regarding the standard will be submitted during the formal comment period.
Response:		
Omaha Public Power District	Negative	Please see MRO's comments submitted via Comment Form.

Organization	Yes or No	Question 10 Comment
Response:		
Orlando Utilities Commission	Negative	Per LPPC comments
Response:		
PJM Interconnection, L.L.C.	Negative	PJM does not believe that the BA should be the entity responsible for the frequency response obligation, moreover the SDT has not sufficiently vetted the issue of applying the response requirements on an entity that cannot provide that service. PJM is concerned that the proposed draft does not explicitly cover the FERC Order 693 directives in the proposed requirements and rather addresses the directives indirectly in the attachments. This matter of mandatory vs. informational attachments must be formally clarified before approval can be given for this approach. PJM does not agree with the additional clarifying phrases being incorporated into the requirements. Explanatory phases should be included as text boxes as proposed in NERC's Risk Based Methodology.
Response: generator responsibility **Att response** **Language cleanup**		
Portland General Electric Co.	Negative	PGE agrees with the WECC whitepaper including the comments and concerns.
Response: see wecc comments		
Potomac Electric Power Co.	Negative	The proposed standard is not reliability centered and will not improve reliability. 5) Potomac Electric Power Company supports the comments provided by PJM.

Organization	Yes or No	Question 10 Comment
Response:		
PPL Electric Utilities Corp.; PPL Generation LLC	Negative	The PPL Companies do not support proposed Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) primarily because PPL believes it inappropriately subjects Reserve Sharing Groups (RSGs) to the proposed requirements. The proposed Applicability provision states that the mandatory reliability requirements would be applicable to (1) Balancing Authorities and (2) Reserve Sharing Groups (where applicable). However, it is unclear how the proposed requirements would be applicable to an RSG. RSGs typically do not provide a mechanism for sharing automatic Frequency Response. The BA Frequency Response Obligation (FRO) is a formula based on BAs and the Interconnection and has nothing to do with RSGs. Rather, RSGs collectively respond to requests for activation of contingency reserves generally after the request is made by a member Balancing Authority. The Standard Drafting Team should therefore remove RSGs from the Applicability section and should remove all other references to RSGs in the proposed standard.
Response: rsg response		
PPL EnergyPlus LLC	Negative	Please refer to PPL's corporate comments.
Response:		
Public Utility District No. 1 of Snohomish County/Snohomish County PUD No. 1	Negative	Public Utility District No. 1 of Snohomish County supports the comments filed by Seattle City Light.
Response:		
Rochester Gas and Electric	Negative	RG&E supports comments to be submitted to NPCC.

Organization	Yes or No	Question 10 Comment
Corp.		
Response:		
Seattle City Light	Negative	LADWP and SCL support project 2007-12's general approach to frequency response, and is prepared to support the ballot once several problematic details are corrected. o LADWP and SCL note that the time allowed to analyze the final "official" set of 25 events for each year, from Dec 15 to Jan 10, is relatively short and coincides with the holiday vacation season
Response: criteria should allow BA to develop tools to be prepared **Also, will be posting "preliminary" list of events during the year** **Std allow minimum 30 days for BAs to get information**		
Seattle City Light	Negative	SCL would like to see addressed in the Standard how the case is to be addressed where a BA simply has no frequency response information to provide, as could happen for a small 1-2 generator BA which has its generators out of service for an extended period for maintenance or upgrades. Assuming the BA purchases frequency response services from another entity during this period, is the BA out of compliance with the proposed Standard simply because it has no data report? And how is its next-year obligation to be computed? These issues should be addressed in the Measures or Additional Compliance information. If these are issues for "lawyers" as the Standards Drafting Team indicated during the November 14, 2011, webinar then the team should engage a NERC lawyer to resolve them prior to releasing the Standard for ballot. o Finally, SCL points out that the proposed Standard introduces a new obligation on applicable entities to maintain frequency responsive reserves. Although this obligation does not appear to be unreasonable or problematic in general, compliance may prove difficult for some entities and in some localized areas.

Organization	Yes or No	Question 10 Comment
Response: yes – you can purchase FR to be compliant -		
South California Edison Company	Negative	SCE's "No" vote, like the WECC position, regarding Project 2007-12 is based on the following five points: 1) Clarification is needed whether there will/ will not be conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction 2) Confusion exists between Attachment A and the Background Document: 2a) Attachment A states peak load allocation is based on “Projected” Peak Loads and Generation, versus 2b) The Background Document which states it will use “historical” Peak Load and Generation. 3) Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response. 4) There is no clear statement of what is expected from the Balancing Authorities and whether or not there is a limit on that expectation. 5) Why are there no requirements on governor installation, settings, and operation for a frequency response standard?
Response: 1) r3 removed **2) allocation methodology corrected** **3) reduction response** **4) dave L**		

Organization	Yes or No	Question 10 Comment
5) generator req		
Southwest Power Pool, Inc.	Negative	Please refer to the IRC Standards Review Committee comments which SPP is a party to for our concerns and recommendations for this standard.
Response:		
Western Area Power Administration	Negative	1. Reducing frequency bias obligation is a detriment to reliability of interconnection and the proposed standard aims to reduce the bias obligation from the current minimum level of 1% load to 0.8% and subsequently to a lower percentage. 2. The proposed standard is very confusing and complex in regard to data collection and compliance. 3. The proposed standard is encompassing reserve sharing group (where applicable), why? What reserve sharing group operates AGC? It is not clear whether the compliance period is monthly or yearly for R1 & R5. The issue of non-binding standard and whether it serves a purpose to go through complicated data submission and found in compliance or out of compliance without any consequences.
Response: 1. Reduction response 2. 3. R1 states “annual” - clean up R5		
Xcel Energy, Inc.	Negative	Please see Xcel Energy’s formal comments, submitted separately.
Response:		
	Negative	59.6 Hz should be used as the Eastern Interconnection URLS. Installed capacity should always be used determining an area's frequency response

Organization	Yes or No	Question 10 Comment
		obligation. I question the use of supplemnetal regulation as a method of procuring frequency response. Is this an acceptable practice throughout all NERC Regions? Each Balancing Authority must be able to provide the required or calculated frequency response and be able to incorporate the proper frequency bias settings in the Balancing Authority's AGC system. A link should be provided in the proposed standard to FRS Form 1.
Response: ISO NE response		

END OF REPORT