Consideration of Comments

Project 2010-14.1 (BAL-002-2)
Phase 1 of Balancing Authority Reliability-based Controls: Reserves

The Balancing Authority Reliability-based Controls: Reserves Drafting Team thanks all commenters who submitted comments on the proposed revisions to BAL-001-2 Real Power Balancing Control Performance. These standards were posted for a 45-day public comment period from March 12, 2013 through April 25, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 55 sets of comments, including comments from approximately 179 different people from approximately 108 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Based on industry comments the drafting team made the following clarifying modifications to the proposed standard and associated documents.

- Modified the definition for a Balancing Contingency Event to provide additional clarity.
- Modified the definition for a Reportable Balancing Contingency Event to use Interconnection specific thresholds instead of a continent wide threshold.
- Modified Requirements R1 and R2 to provide additional clarity.
- Modified the VSL for Requirement R1 to provide additional clarity.
- Modified the Background Document to provide additional clarity.

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

- A couple of stakeholders felt that the proposed BAL-001-1 draft standard was sufficient to cover a DCS event and that BAL-002 could be deleted. The drafting team appreciated their comments and recognized the potential overlap of BAL-001 and BAL-002. However, the drafting team did not believe the time was right for combining the two standards. The drafting team believes that in order to advance this process of combing the two standards these two proposed standards need to move forward. The drafting team supports moving this issue forward and is committed to submit a SAR supporting this concept for future development.
- Some stakeholders questioned why the drafting team was not using the term Reportable Disturbance. The drafting team explained that the term Disturbance as defined by the NERC Glossary of terms is extremely broad and not specific. The Term Balancing Contingency Event was defined to allow the drafting team to be more specific as to what should be considered for the purposes of this standard.
- A couple of stakeholders wanted the drafting team to use BAAL as the measure for performance in this standard. The drafting team explained that they considered using the approach of BAAL as the measure for performance in this standard but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.

- A few stakeholders felt that there should only be a statement in the applicability section stating that this standard did not apply to a BA when it was in an EEA Level 2 or 3. The drafting team explained that they included it in both the applicability section and in the requirement to assure no misinterpretation by the auditors.

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

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

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

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

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coodinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
9.	Michael Jones	National Grid	NPCC	1

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

10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Brian Shanahan	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Russel Mountjoy-Secretary	MRO NERC Standards Review Forum	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel	MRO	1, 3, 5, 6
2.	Dan Inman	MPC	MRO	1, 3, 5, 6
3.	Dave Rudolf	BEPC	MRO	1, 3, 5, 6
4.	Jodi Jensen	WAPA	MRO	1, 6
5.	Joseph Depoorter	MGE	MRO	3, 4, 5, 6
6.	Ken Goldsmith	ALTW	MRO	4
7.	Lee Kittleson	OTP	MRO	1, 3, 5
8.	Marie Knox	MISO	MRO	2
9.	Mike Brytowski	GRE	MRO	1, 3, 5, 6
10.	Scott Bos	MPW	MRO	1, 3, 5, 6
11.	Scott Nickels	RPU	MRO	4
12.	Terry Harbour	MEC	MRO	1, 3, 5, 6
13.	Tom Breene	WPS	MRO	3, 4, 5, 6
14.	Tony Eddleman	NPPD	MRO	1, 3, 5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
2.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
3.	Jerry McVey	Sunflower Electric Power Corporation	SPP	1
4.	Kevin Nincehelser	Westar Energy	SPP	1, 3, 5, 6
5.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6
6.	Allan George	Sunflower Electric Power Corporation	SPP	1

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Harrison	AECI	SERC	3, 5, 6, 1
2.	Ray Phillips	AMEA	SERC	4
3.	David Jendras	Ameren	SERC	1, 3
4.	Kevin Johnson	Big Rivers	SERC	1
5.	Colby Brett Bellville	Duke	SERC	1, 3, 5, 6
6.	Mike Lowman	Duke	SERC	1, 3, 5, 6
7.	Tom Pruitt	Duke	SERC	1, 3, 5, 6
8.	Terry Bilke	MISO	SERC	2
9.	Brad Gordon	PJM	SERC	2
10.	Jim Case	Entergy	SERC	1, 3, 6
11.	Wayne Van Liere	JGE-KU	SERC	1, 3, 5, 6
12.	Phil Whitmer	Georiga Power Company	SERC	3
13.	Bill Thigpen	PowerSouth	SERC	1, 5
14.	Tim Hattaway	Power South	SERC	1, 5
15.	Troy Blalock	SCE&G	SERC	1, 3, 5, 6
16.	Glenn Stephens	SCPSA	SERC	1, 3, 5, 6
17.	Sammy Roberts	Progress Energy	SERC	1, 3, 5, 6
18.	Rene Free	SCPSA	SERC	1, 3, 5, 6
19.	Tom Abrams	SCPSA	SERC	1, 3, 5, 6
20.	John Rembold	SIPC	SERC	1

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

21.	Cindy Martin	Southern	SERC	1, 5
22.	Jimmy Cummings	Southern	SERC	1, 5
23.	M. D. Tucker	Southern	SERC	1, 5
24.	Randy Hubbert	Southern	SERC	1, 5
25.	Kelly Casteel	TVA	SERC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
5.	Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	
4.	mike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Greg Rowland	Duke Energy	X		X		X	X				

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

				1	2	3	4	5	6	7	8	9	10
7.	Group	Kent Kujala	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Al Eizans		RFC	3, 4, 5
2.	Dan Herring		RFC	3, 4, 5

				1	2	3	4	5	6	7	8	9	10
8.	Group	John Allen	Iberdrola USA	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph Turano	Central Maine Power	NPCC	1
2.	Raymond Kinney	New York State Electric & Gas	NPCC	1

				1	2	3	4	5	6	7	8	9	10
9.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Affiliates	RFC	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
3.			WECC	5								
4. Elizabeth Davis	PPL EnergyPlus, LLC		MRO	6								
5.			NPCC	6								
6.			SERC	6								
7.			SPP	6								
8.			RFC	6								
9.			WECC	6								
10. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				
Additional Member	Additional Organization	Region	Segment Selection									
1. Tim Beyrle	City of New Smyrna Beach	FRCC	4									
2. Jim Howard	Lakeland Electric	FRCC	3									
3. Greg Woessner	Kissimmee Utility Authority	FRCC	3									
4. Lynne Mila	City of Clewiston	FRCC	3									
5. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4									
6. Randy Hahn	Ocala Utility Services	FRCC	3									
11. Group	Marie Knox	MISO Standards Collaborators		X								
Additional Member	Additional Organization	Region	Segment Selection									
1. Joe O'Brien	NIPSCO	RFC	6									
12. Group	Ronald L Donahey	Tampa Electric Company	X		X		X	X				
Additional Member	Additional Organization	Region	Segment Selection									
1. Sara E Young			1									
2. Benjamin Smith III			6									
3. James Rocha			5									
13. Group	Pamela R. Hunter	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
No additional members listed.												
14. Group	H. Steven Myers	ERCOT		X								

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Matt Morais	ERCOT	ERCOT	2
2.	Sandip Sharma	ERCOT	ERCOT	2
3.	Matt Stout	ERCOT	ERCOT	2
4.	Ken McIntyre	ERCOT	ERCOT	2
5.	Stephen Solis	ERCOT	ERCOT	2
6.	Vann Weldon	ERCOT	ERCOT	2
7.	Jeff Healy	ERCOT	ERCOT	2

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
3.	John Shaver	Southwest Transmission Cooperative	WECC	1
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terri Pyle	Oklahoma Gas & Electric	SPP	1
2.	Donald Hargrove	Oklahoma Gas & Electric	SPP	3
3.	Leo Staples	Oklahoma Gas & Electric	SPP	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	Terry Bilke	IRC-SRC		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Stephanie Monzon	PJM	RFC	2
2.	Ben Li	IESO	NPCC	2
3.	Kathleen Goodman	NEISO	NPCC	2
4.	Greg Campoli	NYISO	NPCC	2

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

	Additional Member	Additional Organization	Region	Segment Selection
5.	Charles Yeung	SPP	SPP	2
6.	Ali Miremadi	CAISO	WECC	

				1	2	3	4	5	6	7	8	9	10
19.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bart McManus		WECC	1
2.	Dave Kirsch		WECC	1
3.	Ayodele Idowu		WECC	1
4.	Don Watkins		WECC	1
5.	Pam VanCalcar		WECC	5
6.	Fran Halpin		WECC	5

				1	2	3	4	5	6	7	8	9	10
20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
21.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
22.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
23.	Individual	Stephanie Monzon	PJM Interconnection, LLC		X								
24.	Individual	Ken Gardner	Alberta Electric System Operator		X								
25.	Individual	Tom Siegrist	EnerVision, Inc.							X			
26.	Individual	John Tolo	Tucson Electric Power	X									
27.	Individual	Rich Hydzik	Avista	X		X		X					
28.	Individual	Nazra Gladu	Manitoba Hydro			X		X	X				
29.	Individual	Rich Salgo	NV Energy	X		X		X					
30.	Individual	Anthony Jablonski	ReliabilityFirst										X
31.	Individual	Joe Tarantino	SMUD	X		X	X	X	X				
32.	Individual	Jim Cyrulewski	JDRJC Associates LLC	X									
33.	Individual	Greg Travis	Idaho Power Company	X									
34.	Individual	Michael Falvo	Independent Electricity System Operator		X								
35.	Individual	Howard F. Illian	Energy Mark, Inc.								X		
36.	Individual	Kenneth A Goldsmith	Alliant Energy				X						

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
37.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
38.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				
39.	Individual	Kathleen Goodman	ISO New England Inc.		X								
40.	Individual	Thad Ness	American Electric Power	X		X		X	X				
41.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
42.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
43.	Individual	Don Jones	Texas Reliability Entity										X
44.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X		X		X	X				
45.	Individual	Brian Murphy	NextEra Energy	X		X		X	X				
46.	Individual	Robert Blohm	Keen Resources Ltd.								X		
47.	Individual	Steven Wallace	Seminole Electric Cooperative, Inc.			X	X	X	X				
48.	Individual	Christopher Wood	Platte River Power Authority	X		X		X	X				
49.	Individual	Spencer Tacke	Modesto Irrigation District			X	X		X				
50.	Individual	Thomas Washburn	FMPP						X				
51.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
52.	Individual	John Bee on Behalf or Exelon and its Affiliates	Exelon	X		X		X					
53.	Individual	William O. Thompson	NIPSCO					X					
54.	Individual	David Gordon	Massachusetts Municipal Wholesale Electric Company					X					
55.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

DTE Electric	Agree	MISO
Iberdrola USA	Agree	NPCC
Tampa Electric Company	Agree	Duke Energy
Tennessee Valley Authority	Agree	SERC OC Standards Review Group
JDRJC Associates LLC	Agree	Midwest ISO
Alliant Energy	Agree	MRO NSRF
City of Austin dba Austin Energy	Agree	ERCOT
Public Service Enterprise Group	Agree	PJM Interconection
Entergy Services, Inc. (Transmission)	Agree	SERC OC Standards Review Group
Platte River Power Authority	Agree	Public Service Company of Colorado (Xcel Energy)
FMPP	Agree	FMPA

NIPSCO	Agree	MISO
Massachusetts Municipal Wholesale Electric Company	Agree	Northeast Power Coordinating Council, Inc (NPCC)ISO New England, Inc.

1. **The BARC SDT has modified the definition for Balancing Contingency Event based on comments received from the industry. Do you agree that the modifications provide addition clarity? If not, please explain in the comment area below.**

Summary Consideration: Some commenters were confused as to what was meant by the term "loss of a known load". The SDT explained that they had removed this term and added clarifying language.

A couple of commenter felt that the definition was not complete since it did not specify a unit's failure to start. The SDT stated that an earlier version of the definition did contain language recognizing a unit's failure to start. The SDT removed this due to overwhelming objection from the industry for including this term.

One commenter suggested that the SDT incorporate the concept of an unexpected event with the loss itself rather than tying it to the change in ACE. The SDT explained that the use of resource loss for determining an event size and ACE in determining recovery from an event has long been used by the industry and is in both the definition of a Disturbance and Reportable Event. The drafting team chose not to alter this practice. Additionally this compliments all the subsections of the definition, such that there is not a Balancing Contingency Event without a change in ACE.

Organization	Yes or No	Question 1 Comment
SPP Standards Review Group	No	We would suggest incorporating the concept of an unexpected event with the loss itself rather than tying it to the change in ACE. For example in Subsection A, we would propose: 'Sudden, unexpected loss of generation...' Similar changes need to be made to Subsections B and C. Also, there is a timing element associated with Subsection B which could cause conflict with the wording in B. Requiring a sudden loss of import by the loss of a transmission element, implies that the loss of import would be sudden. It may or may not be. It depends on when the loss is reflected in schedules. Additionally, an entity may not know that the loss is due to a loss of transmission. We would suggest: 'Sudden, unexpected loss of an import

Organization	Yes or No	Question 1 Comment
		that causes a change to the responsible entity's ACE.' In Subsection C we suggest: 'Sudden unexpected loss of a known load...'The term 'responsible entity' is not capitalized in the definition but is in the standard. Should it be in the definition?
Response: Thank-you for your comments. The use of resource loss for determining an event size and ACE in determining recovery from an event has long been used by the industry and is in both the definition of a Disturbance and Reportable Event. The drafting team chose not to alter this practice. Additionally this compliments all the subsections of the definition, such that there is not a Balancing Contingency Event without a change in ACE. With regards to your comment concerning Section B the drafting team has made a modification to add clarity. The term "responsible entity" is not in the NERC Glossary and should not be capitalized.		
seattle city light	No	Seattle City Light considers the definition of Balancing Contingency Event proposed in this draft of BAL-002-2 to be incomplete in that it does not recognize the failure of a unit to start as an "event." Seattle recommends revising the definition to read: "A.a.i. Unit Tripping or failure to start at the scheduled time."
Response: Thank you for your comment. Based on the initial posting, the SDT removed "failure to start" from the definition due to the overwhelming objection from the industry on including this within the definition.		
Duke Energy	No	o The definition is too broad. Using the phrase "or any series of such otherwise single events" leaves much open to interpretation. In many cases it will not be clear when the 15-minute clock has been triggered. o Regarding Subsection "C.", it is also not clear what is meant by the "sudden loss of a known load used as a resource". Is the team referring to an interruptible load resource, fully loaded and counted on for provision of contingency reserve? If so, would the sudden loss of the resource mean that the load is inadvertently interrupted causing high ACE? We're not aware of a proven reliability risk that warrants a 15-minute recovery period from a high ACE. Or, is the team referring to an interruptible load resource

Organization	Yes or No	Question 1 Comment
		already implemented (curtailed) for a first contingency, and then somehow losing the curtailment capability where the resource fully loads again causing low ACE (second contingency)? If so, has any such event ever been documented to warrant placing a statement subject to interpretation in the Standard? o Duke Energy suggests striking Subsection “C.”, as loss of any load is covered under the BAAL in BAL-001-2. o Based upon the above, Duke Energy suggests revising the definition to - “Balancing Contingency Event: Any single event described in Subsection (A) or (B) below, or any combination of those events occurring within less than one minute.” Duke Energy suggests revising Subsection “A.b” to read “And, that causes an unexpected negative change to the responsible entity’s ACE”, and suggests revising Subsection “B” to state “Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected negative change to the responsible entity’s ACE.” Both changes are suggested to clarify that this standard is applicable to the loss of resource causing an unexpected drop in ACE. To the extent that Subsection “C” is retained, Duke Energy suggests a similar revision to insert the word “negative”.
Response: Thank-you for your comments and the SDT provides the following responses: 1. **The SDT discussed this topic at length and it is not whether the loss is a single event or a series of single events, the triggering factor is the total loss within the rolling one minute time frame.** 2. **The SDT has modified Section C to address concerns expressed by the industry. The term “known load” is no longer used in the definition.** 3. **The definition has been revised after consideration of Duke Energy's comments.**		
PPL NERC Registered Affiliates	No	The PPL NERC Registered Affiliates suggest striking the language “due to forced outage of transmission equipment.” A responsible entity can cut a

Organization	Yes or No	Question 1 Comment
		tag for reasons other than a forced outage of transmission equipment (equipment OLs, contingency/stability/voltage criteria, etc.) - the sink BA experiencing the loss of the import may not know the reason and thus not know if the loss meets the definition of a Balancing Contingency Event. The SDT replied to this comment during the Formal Comment Period, but missed the point. The curtailment would be communicated, however, the reason, "due to ..." would not necessarily.
Response: Thank you for your comments but the SDT believes that requiring any such loss to be accompanied by "an unexpected change to the responsible entity's ACE" resolves your concerns. In addition, the SDT has modified the definition to provide further clarity.		
MISO Standards Collaborators	No	
ACES Standards Collaborators	No	(1) We appreciate the changes that have been made to the Balancing Contingency Event definition. It is much less complicated and more clear as a result. However, there still has not been a justification provided for the need of the definition. There is a statement in the background document that the previous version of the standard was "broad and could be interpreted in various manners". A specific explanation how the definition addresses the ambiguity should be provided. (2) We disagree with including subsection (c) in the Balancing Contingency Event definition. Subsection (c) includes sudden "loss of a known load used as a resource". Loss of a load will result in positive ACE regardless of whether it is being used a resource or not. As a result, BAL-002-2 R1 will be duplicative with BAL-013-1 R1. Both will compel recovery of ACE from the loss of a load. Think of it this way. If a 1000 MW load is used as a resource to respond to a BA's ACE that is at -100 MW, there would be 900 MW of load remaining once the load is reduced. If that load is then lost, ACE goes to 900 MW. Shouldn't this be covered by the proposed BAL-013-1?

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comments:
1. The SDT chose to use a more specific and granular definition rather that the current definition – Disturbance which is broad and vague and is subject to interpretation.
2. The SDT interprets your comments as being a loss of load event which was not the intention. Section C has been modified to clarify the intention and address concerns expressed by the industry.</td></tr>
<tr><td>Oklahoma Gas & Electric</td><td>No</td><td>The definition of Reportable Balancing Contingency Event includes “the lesser of 80 percent of the MSSC or 500 MW”. We believe that the threshold of 500 MW is too low. This is going to result in an excessive number of “reportable” events that do not have an impact on reliability. The retrieval and analysis of data will be burdensome and provide little value.</td></tr>
<tr><td colspan="3">Response: The SDT has modified the definition to address the concerns expresses by the industry regarding the threshold. Please refer to the Background Document for further clarification on this issue.</td></tr>
<tr><td>IRC-SRC</td><td>No</td><td>We don't see the need for the added definition.</td></tr>
<tr><td colspan="3">Response: The SDT chose to use a more specific and granular definition rather that the current definition – Disturbance which is broad and vague and is subject to interpretation.</td></tr>
<tr><td>Bonneville Power Administration</td><td>No</td><td>BPA recommends further clarity and explanation for the sudden unplanned outage of a transmission facility, and sudden loss of known load used as a resource that causes an unexpected change to responsible entity’s ACE. BPA also recommends leaving in the failure to start language that has been removed.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
If loss of a transmission facility results in an unexpected change to ACE it meets the definition.
The SDT has modified Section C to address concerns expressed by the industry. The term “known load” is no longer used in the</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
definition. **Based on the initial posting, the SDT removed “failure to start” from the definition due to the overwhelming objection from the industry on including this within the definition.**		
Avista	No	The changes to the definitions add clarity, but ambiguity still exists around one phrase. What constitutes an “unexpected change to the responsible entity’s ACE?” Does this mean that there is no human action when the ACE change occurs? Does this mean that a human action to change a Net Interchange value in the ACE equation is “unexpected” when it is due some force majeure condition? Clarity around this issue is necessary to prevent Balancing Authorities (BA) from merely adjusting their Net Schedule Interchange value to correct ACE and passing the problem on to another BA. If transmission curtailments and unexpected adjustments to e-tags are acceptable events to deploy contingency reserve and are considered “Sudden Loss of Generation” under BAL-002-2, this needs to be explicitly stated. If transmission curtailments and unexpected adjustments to e-tags are NOT acceptable events to deploy contingency reserve and are NOT considered “Sudden Loss of Generation” under BAL-002-2, this needs to be explicitly stated. The Background Document discusses frequency deviations on Page 4 under “Balancing Contingency Event.” This seems to preclude any human action to alter Net Scheduled Interchange as a “Balancing Contingency Event.”
Response: Thank you for your response. The SDT considers the word “unexpected” to be clear and to be accepted by the industry. **The SDT is unsure as to the meaning of your comment concerning the Background Document and human action. Without further clarity the SDT cannot provide a response.**		
NV Energy	No	Inclusion of “Sudden loss of a known load” is at odds with the Contingency

Organization	Yes or No	Question 1 Comment
		Reserve definition, especially in light of the fact that loss of load cause ACE to increase (become more positive). In other words, why would one carry reserves to handle a decrease in load? It's illogical. What the SDT may be trying to reference is the use of interruptible load as a type or reserve. As such, load should not be in the Contingency Event definition.
Response: Thank you for your response. The SDT disagrees that it is trying to reference interruptible load as a type of reserve. The SDT has modified Section C to address concerns expressed by the industry. The term "known load" is no longer used in the definition.		
Energy Mark, Inc.	No	The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is.
Response: Thank you for your response. The drafting team suggests that you intended to say "Reporting ACE" since "Reportable ACE" has not been proposed as a new definition. We agree with you suggestion, that the proposed definition of "Reporting ACE" should be included in both this standard and BAL-001-2 until it is approved and included in the Glossary.		
Tacoma Power	No	Tacoma Power is unfamiliar with the phrase, "... known load used as a resource ..." We believe the industry cannot interpret these words consistently. Instead, we suggest using the phrase, "... interruptible load claimed as available reserves ...," which is Tacoma Power's interpretation.
Response: Thank you for your response. The SDT has modified Section C to address concerns expressed by the industry. The term "known load" is no longer used in the definition.		
Hydro-Quebec TransEnergie	No	The definition is not explicitly clear about normal operating actions such as special protection system (SPS) actions. Certain transmission events may lead to generation rejection so the system stays stable after the fault. If we interpret the proposed definition and use the same terminology, these actions are planned, the change on the ACE is not unexpected, and they

Organization	Yes or No	Question 1 Comment
		could be considered as a secondary event. The generation does not become unavailable following the trip. Consequently, these events would not classify as Balancing Contingency Events. During the 04/02/2013 webinar, the Standard Drafting Team provided an answer in this direction. We then understand that a CR Form 1 should not be filled for these types of events. However, we believe that the Balancing Contingency Event definition should be clarified to minimize the risk of misinterpretation if this is the SDT's intent. We suggest adding a bullet in the definition stating that normal operating characteristics of a unit or a system such as SPS actions do not constitute a sudden or unanticipated loss and are not subject to this definition. Additionally, some single contingencies may lead to generation loss as well as load loss after the breaker operations. For example, if 1200 MW of generation is loss and 1000 MW of DC converters at the same time, the net loss for the grid is 200 MW, which would be under the Reportable Balancing Contingency Event threshold. For this reason, the Balancing Contingency Event definition should include the notion of net loss for the grid.
Response: The SDT does not agree with your comment that the definition needs to be modified to address your concern. The activation of a SPS may cause a contingency event on the system with the SPS or another system.		
MISO Standards Collaborators	No	
Texas Reliability Entity	Yes	Definition of "Balancing Contingency Event" is slightly different in Implementation Plan as compared to Standard (A.a.iii. Facility vs Facilities, B. Import vs import...). Definition of "Reportable Balancing Contingency Event " is different in Implementation plan as compared to Standard (Implementation Plan does not include phrase "The 80% threshold may be reduced upon written notification to the Regional Entity.") The Applicability section in the Implementation Plan is also different than the Standard.

Organization	Yes or No	Question 1 Comment
Response: Thanks for the catch, the Standard is correct and the implementation plan will be revised to match the Standard.		
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
SERC OC Standards Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
ERCOT	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
PJM Interconnection, LLC	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
SMUD	Yes	

Organization	Yes or No	Question 1 Comment
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Portland General Electric Company	Yes	
ISO New England Inc.	Yes	
American Electric Power	Yes	
Keen Resources Ltd.	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Xcel Energy	Yes	

2. **The BARC SDT has modified the current definition for Contingency Reserve. Do you agree that the modified definition provides for greater clarity? If not, please explain in the comment area below.**

Summary Consideration: The majority of negative commenters did not agree that the definition need to be modified. The SDT explained that they felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard.

Many commenters question why the SDT included Demand Side Management (DSM) in the definition. The SDT stated that they included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.

Organization	Yes or No	Question 2 Comment
Northeast Power Coodinating Council	No	The last sentence in the definition is not needed, and should be removed. “The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.” is the “How” to meet the contingency reserve requirement, which does not belong in a definition. Suggest to remove this sentence.
Response: Thank you for your comments. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
MRO NERC Standards Review Forum	No	The presently approved NERC definition for contingency seems adequate for this standard. If the DCS definition will not be used any longer, recommend the team retire it from the NERC glossary.
Response: Thank you for your comments. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		

Organization	Yes or No	Question 2 Comment
SPP Standards Review Group	No	As written there is no distinction as to whether ‘unloaded generation’ is on-line or off-line generation. Which is it, or is it both? Additional clarification here would be helpful.
Response: Thank you for your comment. Contingency reserve can be both on-line or off-line generation provided it meets the requirements of the particular Standard in question.		
Duke Energy	No	We would be in agreement except that it includes the term “Balancing Contingency Event”, and we would need our above suggested changes made to that definition to be in agreement here.
Response: Thank you for your comment. The SDT believes that it addressed your concerns with the modifications that have been made to the definition of Balancing Contingency Event.		
PPL NERC Registered Affiliates	No	The PPL NERC Registered Affiliates believe the proposed modifications actually introduce ambiguity and error. Attempting to provide examples (such as...) in definitions is ill-advised as this adds ambiguity to the definition as the list may be considered all inclusive by some and not by others. The final sentence should be struck. As defined by NERC, Demand Side Management includes “all activities” used to “influence” energy usage, which includes programs such as time of day rates, light bulb replacement, and other efficiency programs which do not provide controllable capacity. It appears the SDT may have intended to include the NERC defined term Direct Control Load Management as an example, however, examples need not be included in definitions.
Response: Thank-you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
MISO Standards Collaborators	No	The presently approved NERC definition for contingency seems adequate for this

Organization	Yes or No	Question 2 Comment
		standard.
Response: Thank you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
ACES Standards Collaborators	No	Please strike the last sentence of the definition. It is an explanation of what may constitute contingency reserve and is not actually part of the definition. It should be included in the background document. We understand the reason for the inclusion may be in response to a directive to further the Commission's policy on expanding the use of DSM. However, the use of DSM has expanded significantly since the directives were issued and could be said to have been "overcome" by events. It is well understood within this industry that DSM may be used as a resource. The drafting team could include an explanation in the application guidelines or the background document that would explain that DSM could be used among other resources.
Response: Thank you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
IRC-SRC	No	The presently approved NERC definition for contingency reserve seems adequate for this standard.
Response: Thank you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
Independent Electricity System Operator	No	We generally agree with the revised definition, but do not see the need for the last sentence: "The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation." This is the

Organization	Yes or No	Question 2 Comment
		"How's" to meet the contingency reserve requirement, which does not belong to a definition. We suggest to remove this sentence.
Response: Thank you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
ISO New England Inc.	No	The last sentence in the definition is not needed, and should be removed. "The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation." is the "How" to meet the contingency reserve requirement, which does not belong in a definition. Suggest to remove this sentence. Because of the nature of using hourly integrated values, Requirement R2 may not provide Operators on shift with sufficient information in a timely manner. We recommend an alternative that uses a timer that begins to count up when the BA becomes deficient in contingency reserve, resulting in a compliance violation should the condition persist for 105 minutes. Also, as proposed, it may be create burdensome reporting requirements so that an hourly shortfall can be dismissed due to Balancing Contingency Events, for example.
Response: Thank you for your comments. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive. **It is not clear to the SDT how an operator that uses hourly integrated values would meet the current BAL-002 Standard in effect. R2 is similar to the current requirement R3.1 except that it clarifies that during periods of a "Contingency Event Recovery Period and Contingency Reserve Recovery Period, or during an Energy Emergency Alert Level 2 or 3", an entity does not need to maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency.**		
American Electric Power	No	It is not clear exactly what "other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3)" refers to.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. Other standards, such as EOP-002-3.1 refer to deploying Operating Reserve during EEA 1 or EEA 2. This is an acknowledgement that Contingency Reserve can be deployed as a part of Operating Reserve as allowed in the specific requirements of the various NERC Standards.		
Keen Resources Ltd.	No	The definition is left vague, to enable "double counting" of reserve types. It is a definition not of reserve "allocated" to contingency/restoration, but of reserve that is "usable" for contingency/restoration and which includes the two other defined types of reserve, Frequency Responsive and Regulating. This distinction, between "usable" and "allocated" remains notoriously unclear in this definition, and in apparent contradiction to the provision against double-counting of reserve in the "Guidance Document" currently in preparation. To make the distinction clear, and that occasional "double counting" of reserve types is specifically being allowed by the BAL performance standards, this definition needs to be broken into two definitions. The term "Contingency Reserve" defined in the current definition should be changed to "Reserve Usable for Contingencies" which should be the term used in requirement R2. A second, clear definition of "Contingency Reserve" should be made for use in the Guidance Document, as reserve "allocated" for contingency/restoration, and the term "Contingency Reserve" should thereby be made clearly usable in that document's admonition against double counting of the three types of reserve: Frequency Responsive, Regulating, and Contingency.
Response: Thank you for your comments. The SDT has discussed your comments and will leave the definition as is, except for removing the final sentence as noted in previous responses. **The SDT does not believe that Contingency Reserve should include other types of reserve.** **Double counting is not allowed in the Standard. While during real time deployment of Contingency Reserve, the portfolio of Operating Reserve may be deployed for the contingency, resulting in a potential temporary deficiency of Regulating or Frequency Responsive reserve, the total amount of required Operating Reserve should remain the same.**		

Organization	Yes or No	Question 2 Comment
The SDT feels that additional definitions are unnecessary.		
ERCOT	Yes	ERCOT ISO suggests that the SDT consider the following changes so that the definition of the Contingency Reserve clearly accommodates resources eligible under the respective BA rules to provide Contingency Reserve for that BA: "The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by 'resources eligible under the respective BA rules, including, but not limited to,' resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation."
Response: Thank you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
Salt River Project	Yes	This standard is a big improvement over the existing standard because it provides much needed formal definitions of many terms that are used but not currently defined in BAL-002-1, the definition of Contingency Event, Contingency Reserve and MSSC being three of them.
Response: Thank you for your comment and support.		
Texas Reliability Entity	Yes	The Contingency Reserve definition should mention a Reserve Sharing Group in addition to a BA.
Response: Thank you for your comment. The SDT understands your concern, but does not believe the addition of the RSG in the definition would add to the meaning since RSGs are a grouping of BAs.		
Xcel Energy	Yes	If the DCS definition will not be used any longer, recommend the team retire it from the NERC glossary.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The SDT believes that the term DCS may be used in other standards. If it is not the SDT will look into retiring the definition.		
Manitoba Hydro	Yes	No comment.
SERC OC Standards Review Group	Yes	
seattle city light	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Oklahoma Gas & Electric	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 2 Comment
PJM Interconnection, LLC	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
Avista	Yes	
NV Energy	Yes	
SMUD	Yes	
Idaho Power Company	Yes	
Energy Mark, Inc.	Yes	
Portland General Electric Company	Yes	
Tacoma Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Hydro-Quebec TransEnergie	Yes	

3. **The BARC SDT has created a definition for Reserve Sharing Group Reporting ACE. Do you agree with this definition? If not, please explain in the comment area below.**

Summary Consideration: Many of the commenters did not believe that it was necessary to create a definition for Reserve Sharing Group Reporting ACE. The SDT explained that since the standard used the term Responsible Entity, it required the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.

Several commenters stated that the definition should only apply to BAs participating in the RSG at the time of the event. The SDT agreed with their comment and modified the definition to state this and provide additional clarity.

Organization	Yes or No	Question 3 Comment
Northeast Power Coodinating Council	No	There is no need to define the term Reserve Sharing Group Reporting ACE. This term is not referenced or used in the Standard at all. If the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Preâ€Reportable Contingency Event value, then the Standard is not explicit nor complete enough to place this obligation on the RSG.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
SPP Standards Review Group	No	Do you need to add '...at the time of the measurement' at the end of the definition?
Response: Thank you for your comment. The SDT has made the necessary change.		
SERC OC Standards Review Group	No	The definition should only include the BAs that were participating in the event.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		
Duke Energy	No	Only BA's participating in response to an event should be included in the Reserve Sharing Group Reporting ACE calculation. As we commented on BAL-001-2, ACE should be fully defined in a manner where Reporting ACE can be defined simply as the "The scan rate values of a Balancing Authority's ACE".
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		
PPL NERC Registered Affiliates	No	The PPL NERC Registered Affiliates believe the definition should include only those BAs participating in the specific event, not simply all BAs that are members of the RSG. Suggest revising the definition as follows: -- Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the ACEs (as calculated at such time of measurement) of all of the Balancing Authorities that are participating in the Balancing Contingency Event. --
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		
MISO Standards Collaborators	No	This change was not proposed in the drafting team's SAR and we see no FERC directive to make this change. RSGs have measurement processes that have worked well for quite some time. If the drafting team has guidance on the measurement process, that should be put in a supporting document rather than hard-coding additional obligations in the standard.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company;	No	The definition should include only the BAs asked to participate in the reserve recovery event.

Organization	Yes or No	Question 3 Comment
Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		
ACES Standards Collaborators	No	We believe the definition as proposed is already a common understanding and is not needed. We simply do not see how it adds value. Further, having multiple definitions for ACE creates confusion and is simply not needed.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
IRC-SRC	No	This change was not proposed in the drafting team's SAR and we see no FERC directive to make this change. RSGs have measurement processes that have worked well for quite some time. If the drafting team has guidance on the measurement process, that should be put in a supporting document rather than hard-coding additional obligations in the standard.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
PJM Interconnection, LLC	No	The definition should only include the BA's participating in the event.
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		

Organization	Yes or No	Question 3 Comment
Independent Electricity System Operator	No	We do not see the need to define the term Reserve Sharing Group Reporting ACE. This term is not referenced or used in the standard at all. On the other hand, if the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Preâ€Reportable Contingency Event value, then the standard is not explicit or complete to place this obligation on the RSG.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
Energy Mark, Inc.	No	The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is.
Response: Thank you for your comment. The drafting team suggests that you intended to say "Reporting ACE" since "Reportable ACE" has not been proposed as a new definition. We agree with you suggestion, that the proposed definition of "Reporting ACE" should be included in both this standard and BAL-001-2 until it is approved and included in the Glossary and used consistently throughout.		
ISO New England Inc.	No	There is no need to define the term Reserve Sharing Group Reporting ACE. This term is not referenced or used in the Standard at all. If the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Preâ€Reportable Contingency Event value, then the Standard is not explicit nor complete enough to place this obligation on the RSG.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
Seminole Electric Cooperative, Inc.	No	As written, it arbitrarily precludes the calculation of an RSG ACE for an entire RSG based upon the aggregate frequency bias, and the RSG participants' net interchange with non-participants. The Florida Reserve Sharing Group monitors participants'

Organization	Yes or No	Question 3 Comment
		individual ACE, but calculates an RSG ACE based on the aggregate frequency biases and net interchange with non-participants.
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		
Modesto Irrigation District	No	It is in conflict with the very definiton of a balancing authority.
Response: Thank you for your comment. Unfortunately, the SDT would need additional information to provide a response to your comment.		
seattle city light	Yes	Note there are differing reference to Regulating Reserve Sharing Group and Reserve Sharing Group BAL-001-2 and BAL-002-2. Seattle City Light recommends consistent terminology across the standards.
Response: Thank you for your comment. The SDT has corrected this and is now using a single term.		
Avista	Yes	The assumption is made that algebraic sum of the ACE's is as follows:Reserve Sharing Group Reporting ACE = ACE(BA1) + ACE(BA2) + ACE(BA3) + ...An example calculation would be helpful and provide clarity.
Response: Thank you for your comment. The SDT has modified the definition to provide additional clarity as to how it is calculated.		
Salt River Project	Yes	Same comment as for #2.
Manitoba Hydro	Yes	No comment.
MRO NERC Standards Review Forum	Yes	
Oklahoma Gas & Electric	Yes	
Bonneville Power	Yes	

Organization	Yes or No	Question 3 Comment
Administration		
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
NV Energy	Yes	
SMUD	Yes	
Idaho Power Company	Yes	
Portland General Electric Company	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Texas Reliability Entity	Yes	
Keen Resources Ltd.	Yes	
Hydro-Quebec TransEnergie	Yes	
Xcel Energy	Yes	

4. **The BARC SDT has added language to the proposed requirements in the standard and to the definition for Contingency Reserve to resolve any conflicts between this standard and the EOP standards. Do you agree that this modification was necessary and that any possible issues are now resolved? If not, please explain in the comment area.**

Summary Consideration: Several commenters felt that there should only be a statement in the applicability section stating that this standard did not apply to a BA when it was in a EEA Level 2 or 3. The SDT explained that they included it in the applicability section and in the requirement in order to assure no misinterpretation by the auditors.

A few commenters felt that this standard blurred the current "clear and well-established criteria" of what triggers a DCS event. The SDT stated that they disagreed that a "well-established criteria of what triggers the DCS event" is defined, and attempted to provide a more specific definition. NERC definition of a Disturbance also is not clear and well defined. What is defined is in the eye of the auditor, and the drafting team believes it has provided more granularity and specificity.

Organization	Yes or No	Question 4 Comment
MRO NERC Standards Review Forum	No	All that's needed is a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
Response: Thank you for your comment. The drafting team included it in both locations in order to assure no misinterpretation by the auditors.		
PPL NERC Registered Affiliates	No	The PPL NERC Registered Affiliates do not agree with the proposed modifications to the NERC defined term Contingency Reserve as explained in our comment 2.
Response: Thank you for your comment. The drafting team understands your comment associated with Question No. 2, however, the drafting team is not sure as to the meaning of your comment as it pertains to Question No. 4. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as		

Organization	Yes or No	Question 4 Comment
stated in the EOP-002 Standard.		
MISO Standards Collaborators	No	It needs a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
Response: Thank you for your comment. The drafting team included it in both locations in order to assure no misinterpretation by the auditors.		
ACES Standards Collaborators	No	(1) We do believe that it is helpful to clarify that a BA does not have to comply with recovering ACE and contingency reserves when it is in an EEA 2 or 3. It certainly would not make sense to go to the extreme of shedding firm load to recover ACE or contingency reserves if a BA was simply out of balance with no transmission security issues, system frequency issues or stability issues. There are standards requirements such as operating within IROLs/SOLs that would deal with these other reliability issues and provide the indication if load needed to be shed to address the deficient BA. A more efficient way to address this issue may be to apply the restriction in the applicability section. (2) It would be helpful if the drafting team explained what the conflicts with the EOP standards are. Besides the one identified above, are there others? The background document states that there are conflicts but does not explain them. It is difficult to judge if the issue was addressed without an adequate explanation.
Response: Thank you for your comment. **1) The drafting team included it in both locations in order to assure no misinterpretation by the auditors.** **2) The drafting team will provide more explanation within the background document**		
IRC-SRC	No	All that's needed is a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
Response: Thank you for your comment. The drafting team included it in both locations in order to assure no misinterpretation by		

Organization	Yes or No	Question 4 Comment
the auditors.		
ReliabilityFirst	No	a. ReliabilityFirst recommends removing any references to “an Energy Emergency Alert Level 2 or Level 3” since these are not defined terms (Energy Emergency Alert Levels are only noted in Attachment 1, EOP-002-3). ReliabilityFirst believes the BAL-002-2 should stand on its own merit and not rely on conditions within an attachment within another standard. For example, if the Energy Emergency Alert levels designations ever change in the future, this has the potential to have an impact on the intent of the BAL-002-2 standard. For consideration, ReliabilityFirst recommends defining the alert levels within the standard itself as an attachment, hence not relying on another standard for these conditions.
Response: Thank you for your comment. The drafting team has modified the standard to provide additional clarity.		
American Electric Power	No	Please see our response to Q2 in regards to the definition of Contingency Reserve. AEP disagrees with the second half of R1 where it begins with “or... Its Preâ€Reportable Contingency Event ACE Value, (if its Preâ€Reportable Contingency Event ACE Value was negative)...” . The language provided in this section and its sub-bullets are extremely confusing. It appears that the intent is to set an expectation for recovering from multiple contingency events, however the language provided is unnecessarily complex and will likely confuse those responsible for meeting the requirements.
Response: Thank you for your comment. Your comments do not address the specific Question No. 4, however, the drafting team has provided a calculator to perform the calculation and the Background Document to help resolve your conflict.		
Keen Resources Ltd.	No	You mean not "possible issues" but "possible issues related to EOP standards". Otherwise, see answer to question 2 about other issues.
Response: Thank you for your comment. The drafting team has incorporated your suggestion.		

Organization	Yes or No	Question 4 Comment
seattle city light	Yes	This standard is an improvement over the existing BAL-002 because it clarifies the requirements for a Balancing Authority or Reserve Sharing Group regarding Contingency Reserve requirements during Energy Emergency Alerts.
Response: Thank you for your comment.		
Duke Energy	Yes	We agree with the change to R1 to recognize emergency operations as long as the BAAL is implemented in BAL-001-2, as it is the only viable standard for measuring real-time performance and the BA's impact on Interconnection frequency during such operation. Duke Energy agrees that the proposed language in this standard will allow the BA to utilize its contingency reserves to continue to serve load under an Energy Emergency Alert Level 2 or Level 3 while remaining compliant to BAL-002; however under what circumstances, if any, should the Balancing Authority shed firm load as a last resort to ensure that it remains compliant to Requirement R1 under normal operations? In our opinion, the inability of a Balancing Authority to meet the 15-minute DCS compliance threshold does not in itself represent a reliability issue. There are cases in the off-peak times especially where the recovery is detrimental to Interconnection frequency. Some of the revisions in BAL-002-2 blur the clear and well-established criteria of what triggers the DCS event. Too much is left up to after-the fact compliance scrutiny, and operators need unquestionable guidance on this matter. Also, in the definition of Contingency Reserve, add the word "NERC" before the word "contingency" for clarity.
Response: Thank you for your comment. The drafting team does not agree that a "well-established criteria of what triggers the DCS event" is defined, and attempted to provide a more specific definition. NERC definition of a Disturbance also is not clear and well defined. The drafting team believes it has provided more granularity and specificity.		
Texas Reliability Entity	Yes	R2- Disturbance Recovery Period is not defined and should be changed to Contingency Event Recovery Period.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The drafting team has made the necessary corrections to address your concern.		
Avista	Yes	This language clarifies that when in an Energy Alert 2 or 3, the BA is using all available reserves to maintain ACE.
Response: Thank you for your comment.		
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
SPP Standards Review Group	Yes	
SERC OC Standards Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
ERCOT	Yes	
Oklahoma Gas & Electric	Yes	

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
NV Energy	Yes	
SMUD	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Energy Mark, Inc.	Yes	
Portland General Electric Company	Yes	
ISO New England Inc.	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 4 Comment
Seminole Electric Cooperative, Inc.	Yes	
Hydro-Quebec TransEnergie	Yes	

5. **The BARC SDT has developed Requirement R2 which requires entities to have Contingency Reserve at least equal to its MSSC. This requirement was added to address, in conjunction with Requirement R1, the FERC Directive for a continent wide Contingency Reserve policy. Do you agree that this addresses the FERC Directive? If not, please explain in the comment area.**

Summary Consideration: Many commenters felt that BAs may withhold their Contingency Reserve from events other than reportable events so that they always have the necessary reserve obligation. The SDT stated that the present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.

Several commenters stated that the old Policy 1 noted many reasons for operating reserves and that a BA may be reluctant to deploy its reserves since it could start the clock on the available hours. The SDT explained that they agreed that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.

A few of the commenters believed that the standard was a commodity standard and was not performance based. The SDT stated that they had modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693.

Some commenters believed that there was a embedded expectation to recover from and measure multi-contingent events beyond MSSC. The SDT explained that they believed that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves.

A couple of commenters asked the SDT to develop a reserve policy. The SDT stated that they were developing a Operating Reserve Guideline to be presented to the NERC OC for acceptance at their September 2013 meeting.

Organization	Yes or No	Question 5 Comment
MRO NERC Standards Review Forum	No	This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the “available hours” clock Please clarify. The second unintended consequence for those BAs that don’t withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies the carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. Please clarify. The last most significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn’t in the drafting team’s SAR or in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it’s fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. Is the SDT stating that recovery is needed to recover to zero or MSSC? We believe the way a way to achieve the Commissions directive for a continent wide

Organization	Yes or No	Question 5 Comment
		policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.
Response: Thank you for your comment. **[1] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.** **[2] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.** **[3] The SDT believes that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves.** **[4] The SDT modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693** **[5] The SDT is drafting a Reserve Policy Guideline for consideration by the NERC Operating Committee.**		
SERC OC Standards Review Group	No	This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need.The first

Organization	Yes or No	Question 5 Comment
		unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the “available hours” clock. The second unintended consequence for those BAs that don’t withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. We believe a way to achieve the Commissions directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. We agree with the principle of a BA maintaining contingency reserves to respond to its MSSC. However, as R2 is currently proposed it puts the BA at risk if contingency reserves fall below its MSSC for any single sampling period. Indeed, as stated it puts a BA with a 2 second sampling interval at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the Measures and VSL, we believe that the requirement needs to stand on its own and that the

Organization	Yes or No	Question 5 Comment
		specifying language should be included in R2 itself.
Response: Thank you for your comment. **[1] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.** **[2] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.** **[3] The SDT believes that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves.** **[4] The SDT modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693** **[5] The SDT is drafting a Reserve Policy Guideline for consideration by the NERC Operating Committee.**		
seattle city light	No	Seattle City Light finds Requirement R2 and Measure M2 to lack specificity as to what level of performance is required for compliance, and recommends the following changes:"R2. Each Responsible Entity shall maintain an amount of Contingency Reserve such that its clock-minute average of Contingency Reserves is equal or greater than the Most Severe Single Contingency except during the Disturbance Recovery Period and Contingency Reserve Recovery Period, or during an Energy Emergency Alert 2 or 3."" M2. Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, Energy Management System logs, software programs, or other evidence (either hard copy or electronic format) to demonstrate compliance with Requirement R2."

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.		
Duke Energy	No	Requirement R1 and R2 could provide a consistent continent-wide Contingency Reserve policy if the definition of Balancing Contingency Event provided a “bright line” to the industry on what events would be applicable to the determination of MSSC; we believe that Subsection “C.” of that definition should be deleted, per our comment under question #1 above, and if the R2 allowed for other use of Contingency Reserves. Requirement 2 refers to “Disturbance Recovery Period” and “Contingency Reserve Recovery Period” which are no longer defined. Duke Energy would suggest the following change: “Except during the Contingency Event Recovery Period and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or Level 3, each Responsible Entity shall maintain an hourly average amount of Contingency Reserve at least equal to its Most Severe Single Contingency.” Language in Requirement R2 should also recognize that Contingency Reserves may be used from time to time to aid in balancing aside from the loss of resource - today such use takes places and does not impact compliance under DCS.Measure M2 requires that the Contingency Reserve averaged over each clock hour is greater than or equal to the amounts identified in Requirement 2 - however, as the amounts identified in Requirement R2 are allowed to be less than MSSC, it is not clear why the language at the end places an exception only on the 105-minute combined recovery and restoration period, and not on any period such resources may be utilized under an EEA2 or EEA3. Duke Energy would suggest modifying Measure M2 to read at the end “except during

Organization	Yes or No	Question 5 Comment
		an Energy Emergency Alert Level 2 or Level 3, or within the first 105 minutes following an event requiring the activation of Contingency Reserve.” Though an hourly average is proposed, it is not practical for a BA to track its Contingency Reserves in a manner where it would make the choice to increase its Contingency Reserves above the MSSC if it happened to drop below its MSSC for some time in the same hour - it is an unnecessary activity to bring into real-time operations. Also, we believe the Standard Drafting Team should carefully check to make certain that these new definitions don’t impact other existing definitions. Though suggestions have been provided, Duke Energy does not support the adoption of Requirement R2 and agrees with the comments provided by MISO. Performance under the existing BAL-002 has been stellar without the need for an additional requirement to track Contingency Reserves to the extent prescribed. The current DCS is a very effective results-based standard. The existence of a requirement such as R2 will result in inefficient utilization of resources, increased costs, inaccurate representation of resource capability, and other negative consequences with no benefit to reliability.

Response: Thank you for your comment.

[1] The SDT has made further modifications to the definition and believes that these modifications provide sufficient clarity.

[2] The SDT has made the necessary correction.

[3] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.

[4] The SDT disagrees with your comment. The exception does cover EEA Levels 2 and 3. However, the SDT has modified the standard to provide additional clarity.

Organization	Yes or No	Question 5 Comment
[5] The SDT has modified the requirement and measure and believes that the modifications provide the necessary clarity. **[6] The SDT believes that this calculation can be easily accomplished in most standard EMS. The value provided to the System Operator through heightened situational awareness is worth the effort.** **[7] The SDT has checked and believes there are no conflicts.** **[8] We believe that the proposed standard clarifies the intent of the current standard.**		
PPL NERC Registered Affiliates	No	PPL NERC Registered Affiliates do not agree that the development of additional requirements is necessary to meet the FERC directive for a continent wide policy. Additional comments on this topic provided under question 10.
Response: Thank you for your comment. **The SDT has decreased the number of requirements and provided additional clarity. The essence of the proposed R1 and R2 still encompass the intent of the current BAL-002.**		
MISO Standards Collaborators	No	R2 has nothing to do with a Continent Wide Contingency Reserve Policy and there is nothing in the drafting team's SAR that calls for the implementation of a commodity standard. This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies the carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate

Organization	Yes or No	Question 5 Comment
		performance under Policy 1. The last most significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR nor in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. A fundamental flaw in R2 is that drafting team has implemented a commodity expectation that the BA must have contingency reserves above MSSC at all times and yet has provided no clear definition on how this is measured (does it include all generation headroom available in 10 minutes? In 15 minutes? What about resources that are also providing AGC? Does their instantaneous headroom count? Are load resources available in 15 minutes or 10 minutes counted? What type of proof of deliverability is required? Some of the background information implies that frequency responsive resources must be removed from the Contingency Reserve calculation. How much? All headroom? Enough to provide the IFRO?This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the ultimate demonstration of adequacy.We believe the way a way to achieve the Commissions directive for a continent wide "contingency reserve" policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The document the drafting team is working on is a good start. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement

Organization	Yes or No	Question 5 Comment
		reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.
Response: Thank you for your comment. **[1] The SDT has modified the existing standard by eliminating administrative requirements. However, they have maintained requirements associated with performance and addressed the FERC directive in order 693.** **[2] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.** **[3] The SDT believes that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves.** **[4] The SDT does not believe that they have excluded anything that is in the present standard with regards to what would count as contingency reserve but has in actuality provided clarity to the present wording in the current BAL-002.** **[5] The SDT is developing a proposed Reserve Policy Guideline for the NERC OC consideration by the NERC OC.** **[6] The SDT believes that this is outside the scope of the current SAR.**		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	No	The proposed requirement would have significant negative consequences as Reserves are an inventory intended to be used when there is a reliability need.A BA could be encouraged to never deploy their CRs except for during a DCS-reportable event. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the time would start ticking on the ‘available hours’

Organization	Yes or No	Question 5 Comment
Company Generation; Southern Company Generation and Energy Marketing		clock. Additionally, BAs that don't withhold CRs for non-DCS events might feel the need to increase the amount of contingencies they carry in order to always have more reserves than their MSSC which in turn, would increase customer costs without a demonstrated need. We suggest that not all BAs have the same needs for the various types of operating reserves and that performance is the demonstration of adequacy. We suggest the SDT work with the NERC OC to create a policy document that outlines the factors the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves and provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standard's process, we suggest that NERC add these four types of reserves to 'Attachment 1-TOP-005 Electric System Reliability data" with the noted expectation that RCs collect this information in real time for use in the EEA process. While we agree with the principle of a BA maintaining Contingency Reserves to respond to its MSSC, the proposed R2 puts the BA at risk if CR reserves fall below its MSSC for any single sampling period. For example, BAs with a 2 second sampling interval would be at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the proposed Measures and VSLs, we suggest that specific language be included in R2 and not just in the Measure (SERC OC). A reference to the integrated clock hour should be included in R2 as in the Measure.
Response: Thank you for your comment. **[1] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.**		

Organization	Yes or No	Question 5 Comment
[2] The SDT believes that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves. **[3] The SDT is developing a proposed Reserve Policy Guideline for the NERC OC consideration by the NERC OC.** **[4] The SDT believes that this is outside the scope of the current SAR.** **[5] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.**		
ACES Standards Collaborators	No	(1) We are concerned that this requirement will have unintended consequences. As written, a BA will be forced to only deploy contingency reserve for responding to resource contingencies. Consequently, the BA will have to carry more operating reserves which increases their operating costs tremendously without commensurate reliability benefit. Furthermore, there is no data indicating that operating reserves carried by BAs today are insufficient. (2) While contingency reserve is just one type of operating reserve and is intended for use to respond to contingent events, a BA should not be restricted to deploying it only for contingent events. There may be other reasons for a BA to have a large negative ACE (i.e. units don't ramp as expected) and the BA should be free to call upon its contingency reserve to recover ACE in such a situation. Since the FERC directive that is driving this requirement is to establish a continent wide policy on contingency reserve, a better solution would be for NERC to write an operating policy describing appropriate uses of various types of contingency reserves. A guideline document would provide better details for an operating policy than a requirement.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
[1] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility. **[2] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.** **[3] The SDT is developing a proposed Reserve Policy Guideline for the NERC OC consideration by the NERC OC.**		
IRC-SRC	No	We believe this requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the “available hours” clock. The second unintended consequence for those BAs that don’t withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies the carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. The last significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn’t in the drafting team’s SAR or in a directive. Events greater than MSSC should be reported,

Organization	Yes or No	Question 5 Comment
		but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. We believe the way a way to achieve the Commission's directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.

Response: Thank you for your comment.

1] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.

[2] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.

Organization	Yes or No	Question 5 Comment
[3] The SDT believes that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves. **[4] The SDT modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693** **[5] The SDT is drafting a Reserve Policy Guideline for consideration by the NERC Operating Committee.**		
PJM Interconnection, LLC	No	PJM agrees with the principle of a BA maintaining contingency reserves to respond to its MSSC but believe this requirement would have negative unintended consequences. Reserves should be used when there is a reliability need that may or may not be caused by the loss of a resource. This requirement encourages BA's to withhold deployment of contingency reserves except for DCS reportable disturbances. For example, if a BA's ACE is dragging into the top of the hour, along with Interconnection frequency, due to schedule changes and slow unit response, this requirement incentivizes the BA to withhold deploying reserves. If a BA is approaching an IROL that could be mitigated by deploying contingency reserves, this requirement penalizes the BA for doing so, even though the result would benefit the Interconnection. Even if PJM agreed with the proposed R2, which we do not, as written it puts the BA at risk if contingency reserves fall below its MSSC for any single sampling period. Indeed, as stated it puts a BA with a 2 second sampling interval at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the Measures, specifically M2, PJM believes that the requirement needs to stand on its own and that the specifying language should be included in R2 itself. DCS performance in North America has been greatly improved compared to what was considered adequate performance under Policy 1. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of

Organization	Yes or No	Question 5 Comment
		adequacy. We believe a way to achieve the Commission's directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process, as was a directive in 693), NERC could add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data".
Response: Thank you for your comment. **[1] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.** **[2] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.** **[3] The SDT cannot agree or disagree with your comment concerning DCS performance, but does agree that not all BAs have the same needs.** **[4] The SDT is developing a proposed Reserve Policy Guideline for the NERC OC consideration by the NERC OC.** **[5] The SDT believes that this is outside the scope of the current SAR.**		
Alberta Electric System Operator	No	Please consider revising requirement R2 to use the proposed new definitions as follows:R2. Except during the Contingency Event Recovery Period and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3, each

Organization	Yes or No	Question 5 Comment
		Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency. [Violation Risk Factor: Medium] [Time Horizon: Realâ€time Operations]
Response: Thank you for your comment. The SDT has made the necessary corrections.		
Energy Mark, Inc.	No	I believe that this requirement falls under Paragraph 81 and should not be in the standard.
Response: Thank you for your comment. The SDT modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693.		
Keen Resources Ltd.	No	As explained in my Comment to Question 2, the commonly used term "Contingency Reserve" needs to be unpacked into two terms: "Contingency Reserve" (to be used in the "Guidance Document" currently being prepared) and "Reserve Usable for Contingencies" (to be used in this standard instead of "Contingency Reserve"). The FERC Directive 693 did not identify and sort out this ambiguity and called simply for a requirement of undifferentiated "response" to a contingency, without distinguishing between the three intrinsic "types" of response, namely Frequency Response, Regulating Response, and Contingency Response, except to designate the "objective"/cause of the Response. All three types of response can meet that objective. The FERC Directive then sought to expand the definition of Contingency Reserve to include demand-side resources, and to set the requirement of a quantity of "Contingency Reserve", without specifying "Contingency Reserve" as any particular reserve type. So, yes, R2 does address the FERC Directive, but the FERC Directive is itself inadequate for failing to make the all-important distinction between type of reserve, and usability of different reserve types to meet a single reliability objective which would be some generalized "Responding" to a "Contingency" without specifying the "type" of response which distinguishes reserve types. Rather than simply "address" a technically uninformed FERC Directive, NERC should in its superior

Organization	Yes or No	Question 5 Comment
		reliability wisdom/competence seek to improve upon the FERC Directive and establish the precedent that FERC takes technical direction from NERC, not the other way around and without opposing or contradicting FERC.
Response: Thank you for your comment. **The SDT has reviewed your suggested modification to the definitions, but feel that the current definitions, as presently modified, provide for sufficient clarity.** **The SDT is developing a Reserve Policy Guideline for consideration by the NERC OC that will address the concern you have identified in a different manner.**		
Seminole Electric Cooperative, Inc.	No	This standard ahs been and should continue to be results based. R2 imposes a tracking and evidentiary requirement which is unreasonable and is not warranted by past performance and results. If the logical next step to be standards proscribing the measurement, qualification, etc. for contingency reserves?
Response: Thank you for your comment. The SDT modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693.		
Texas Reliability Entity	Yes	A Responsible Entity may have an internal Contingency Reserve policy that is different than the proposed language in R2. While we understand the R2 states the minimum Contingency Reserve amount, should R2 be re-worded to state that each Responsible Entity shall maintain an amount of Contingency Reserve as least equal to its Most Severe Single Contingency or an amount per its Contingency Reserve policy, whichever is larger? Ex. The MSSC in ERCOT is 1375 MW, but the required minimum responsive reserve is 2300 MW, which is the amount necessary to maintain adequate primary frequency response to meet the intent of the BAL-003 standard.
Response: Thank you for your comment. The SDT is only requiring a minimum amount of Contingency Reserve to be available. There is nothing in the standard to preclude an entity to carry additional Contingency Reserve.		

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
SPP Standards Review Group	Yes	
ERCOT	Yes	
Oklahoma Gas & Electric	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
Avista	Yes	
NV Energy	Yes	
SMUD	Yes	

Organization	Yes or No	Question 5 Comment
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Portland General Electric Company	Yes	
ISO New England Inc.	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Modesto Irrigation District	Yes	
Hydro-Quebec TransEnergie	Yes	

6. **The BARC SDT has assigned both Requirement R1 and Requirement R2 a "medium" VRF. Do you agree with the proposed VRF? If not, please explain in the comment area below.**

Summary Consideration: The majority of the negative commenters did not agree with the requirements and therefore could not agree with the VRFs. The SDT explained that they could not determine from the comment what they believed to be unnecessary. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.

Organization	Yes or No	Question 6 Comment
MRO NERC Standards Review Forum	No	We believe the requirement itself is inappropriate, so any VRF is unnecessary.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be unnecessary. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
SERC OC Standards Review Group	No	It is difficult to agree with the VRF's while disagreeing with the standard as proposed.
Response: Thank you for your comment. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified		

Organization	Yes or No	Question 6 Comment
emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
Duke Energy	No	We can't agree, due to the current lack of clarity in the requirements.
Response: Thank you for your comment. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
MISO Standards Collaborators	No	We believe the requirement itself is inappropriate, so any VRF is unnecessary.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be unnecessary. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
ACES Standards Collaborators	No	We agree with the VRF for requirement R1 but do not agree with requirement R2 as written. Thus, we do not agree with the VRF for Requirement R2.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be incorrect. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
IRC-SRC	No	We believe the requirement itself is inappropriate, so any VRF is unnecessary.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be unnecessary. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event.		

Organization	Yes or No	Question 6 Comment
This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
Seminole Electric Cooperative, Inc.	No	Agree with the the VRF for R1, but not R2 for the reasons described in response to Question 6.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be incorrect. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	It is difficult to agree with the VRFs while disagreeing with the standard as proposed.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be unnecessary. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
SPP Standards Review Group	Yes	
seattle city light	Yes	
ERCOT	Yes	
Oklahoma Gas & Electric	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
Avista	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 6 Comment
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Energy Mark, Inc.	Yes	
Portland General Electric Company	Yes	
ISO New England Inc.	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Texas Reliability Entity	Yes	
Keen Resources Ltd.	Yes	
Hydro-Quebec TransEnergie	Yes	

7. **The BARC SDT has assigned both Requirement R1 and Requirement R2 a Time Horizon of "Real-time Operations". Do you agree with the Time Horizon the SDT has chosen? If not, please explain in the comment area below.**

Summary Consideration: The vast majority of the commenters agreed with the use of "Real-time Operations" as the appropriate time horizon.

Organization	Yes or No	Question 7 Comment
Seminole Electric Cooperative, Inc.	No	Same response as Question 6.
Response: Thank you for your comment. Please refer to our response to Question #6.		
Modesto Irrigation District	No	
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
MRO NERC Standards Review Forum	Yes	
SPP Standards Review Group	Yes	
SERC OC Standards Review Group	Yes	

Organization	Yes or No	Question 7 Comment
seattle city light	Yes	
Duke Energy	Yes	
MISO Standards Collaborators	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
ERCOT	Yes	
ACES Standards Collaborators	Yes	
Oklahoma Gas & Electric	Yes	
IRC-SRC	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 7 Comment
Salt River Project	Yes	
PacifiCorp	Yes	
PJM Interconnection, LLC	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
Avista	Yes	
NV Energy	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Energy Mark, Inc.	Yes	
Portland General Electric Company	Yes	
ISO New England Inc.	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Texas Reliability Entity	Yes	

Organization	Yes or No	Question 7 Comment
Keen Resources Ltd.	Yes	
Hydro-Quebec TransEnergie	Yes	

8. The BARC SDT has developed VSLs for Requirement R1 and Requirement R2. Do you agree with the VSLs in this standard? If not, please explain in the comment area.

Summary Consideration: Many of the commenters disagreed with the use of an event by event measure. The SDT explained that currently in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base.

Some commenters stated that the VSL implied that the entity had recovered from the event. The SDT agreed with the commenters and modified the VSL to use the term "partially recovered".

Organization	Yes or No	Question 8 Comment
MRO NERC Standards Review Forum	No	Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base.		
SPP Standards Review Group	No	Change all of the R1 VSLs to read 'The Responsible Entity partially recovered...'
Response: Thank you for your comment; the drafting team has incorporated your suggestion.		
SERC OC Standards Review Group	No	Requirement 1 should not be an event by event obligation. A quarterly average measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they have		

Organization	Yes or No	Question 8 Comment
applied compliance and associated penalties on an event by event base.		
Duke Energy	No	We can't agree, due to the current lack of clarity in the requirements.
Response: Thank you for your comment. The SDT has modified the requirements to provide for additional clarity.		
MISO Standards Collaborators	No	Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base.		
ACES Standards Collaborators	No	We disagree with the VSLs for both requirements. The VSLs for requirement R1 raise the bar significantly for compliance without a technical justification. Today, DCS compliance is determined by a quarterly average of response to events. Thus, failure to recover ACE for two events within the same quarter would be a singular violation. As proposed, the new VSLs would treat each event as a separate violation. Without significant justification, we cannot agree with this change to the VSLs. Because we do not agree with Requirement R2, we do not agree with the corresponding VSLs.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base.		
IRC-SRC	No	Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base.		

Organization	Yes or No	Question 8 Comment
Bonneville Power Administration	No	BPA recommends changing the VSLs for R2 to: Lower VSL more than 2 but less than or equal to 5 hours; Moderate VSL more than 5 but less than or equal to 10 hours; High VSL more than 10 but less than or equal to 15 hours; Severe VSL More than 15 hours.
Response: Thank you for your comments. The SDT believes that the current ranges in the VSL for R2 are more appropriate.		
PJM Interconnection, LLC	No	It is difficult to agree with the VSL's while disagreeing with the standard as proposed.
Response: Thank you for your comment.		
ReliabilityFirst	No	The VSLs for Requirement R2 references "each calendar quarter" while the actual requirement R2 does not require maintaining an amount of Contingency Reserve at least equal to its Most Severe Single Contingency on a quarterly basis. Also, the lower VSL starts with an entity being deficient for more than five hours. This poses a gap; if for example, an entity was deficient between one and four hours. ReliabilityFirst recommends restructuring the VSLs, to be consistent with the language in the requirement, as follows (this is an example of a Lower VSL); "The Responsible Entity maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency but its Contingency Reserve was deficient for less than or equal to 15 hours."
Response: Thank you for your comments. The drafting team has provided clarifying language.		
Tacoma Power	No	Tacoma Power does not understand - all levels state that the Responsible Entity recovered from the event, yet they recovered to less than 100% of the required recovery. How can it be "recovered" without reaching 100% in every case? Instead, we suggest that the VSLs recognize that the Responsible Entity "partially recovered" from the event.
Response: Thank you for your comments. The drafting team has provided clarifying language.		

Organization	Yes or No	Question 8 Comment
Texas Reliability Entity	No	1) R1 VSL- At what point is the ACE measured in order to determine the % of required recovery. We assume it is the lowest ACE value measured during the one-minute period for the Balancing Contingency Event, but this should be clarified.2) R2 VSL - A deficiency less than 5 hours is not covered by the VSL. If the intent is to allow a certain amount of deficiency without penalty, that should be clearly stated in the requirement and not implied in the VSL.3) R2 VSL - Five hours in a calendar quarter of not having sufficient Contingency Reserves seems too long, especially since Contingency Event Recovery Periods and EEAs are excluded. We would recommend a shorter time frame, e.g. 0-3 hours for lower VSL, 3-5 for moderate VSL, 5-10 for high VSL, and >10 for severe VSL. Also, the time frame for each VSL level needs to state if it is cumulative or on a per-event basis (we assume it is cumulative but it should be explicitly stated).
Response: Thank you for your comments. The drafting team has provided clarifying language.		
Seminole Electric Cooperative, Inc.	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they		

Organization	Yes or No	Question 8 Comment
have applied compliance and associated penalties on an event by event base.		
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
ERCOT	Yes	
Oklahoma Gas & Electric	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
Avista	Yes	
NV Energy	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Energy Mark, Inc.	Yes	

Organization	Yes or No	Question 8 Comment
Portland General Electric Company	Yes	
American Electric Power	Yes	
Keen Resources Ltd.	Yes	
Hydro-Quebec TransEnergie	Yes	

9. **The BARC SDT has made significant modifications to the Background Document based on industry comments received. Do you agree that these modifications provide additional clarity as to the development of this standard? If not, please explain in the comment area.**

Summary Consideration: Some of the commenters wanted additional information as to how the threshold of 500 MW was determined. The SDT explained that they had removed the 500 MW threshold for all Interconnections and was now using a threshold unique to each Interconnection. They further stated that they had added language to the Background Document to provide additional clarity on the thresholds.

Manu of the commenters stated that since they disagreed with the requirements then they could not agree with the Background Document. The SDT explained that they had made modifications to the requirements and added clarifying language to the Background Document.

Organization	Yes or No	Question 9 Comment
MRO NERC Standards Review Forum	No	There first needs to be agreement on the requirements before there is concurrence with the background document.
Response: Thank you for your comment.		
SPP Standards Review Group	No	We offer the following suggestions:Page 3 1st paragraph 2nd line - replace ‘They’ with ‘It’4th line - remove the hyphen in ‘15-minute’ 2nd paragraph1st line - remove space following ‘Policy’ and insert space after the period Page 4 1st paragraph under Contingency Reserve

Organization	Yes or No	Question 9 Comment
		2nd line - replace 'its' with 'their' 6th & 7th lines - be consistent with the hyphens in demand side management Page 5 Correct the text formatting for Requirement 1 Page 6 2nd paragraph Capitalize Contingency Reserve 3rd paragraph 1st line - delete space in R1 5th paragraph Reword the 2nd sentence to read: 'Reviewing the data, the drafting team decided to establish a single, continent-wide standard on the median value of generation loss.' Under Violation Severity Levels This needs to be rewritten. The VSLs are based solely on amount of recovery. The paragraph tries to include the sufficiency of response but it's not in the VSLs. Page 10 Last paragraph Needs to be rewritten; what's there refers to R1 not R2.
Response: Thank you for your comment. The drafting team has revised the background document incorporating the majority of you suggestions. **The SDT has modified the VSL to provide additional clarity.**		
SERC OC Standards Review Group	No	The Background Document states on page 4 that "FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation." We disagree with this interpretation of the Commission's directive. In Order 693 (P355) the Commission declined to define a 'significant deviation as a frequency deviation of 20 mHz', but instead directed the ERO 'to define a significant deviation and a reportable event'. The Commission directed that 'loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,' must be taken into account when developing the aforementioned definitions. We believe that the Commission clearly did not intend that any event that causes a frequency deviation, not matter how small, be included

Organization	Yes or No	Question 9 Comment
		in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500 MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample. We question whether this is appropriate and believe that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method. We suggest that additional details be provided in the Background Document relating to the methodology for development of the reporting thresholds.
Response: Thank you for your comment. The SDT has modified the standard to accommodate your comment. **The SDT has modified the Background Document to provide additional clarity as to how the thresholds were developed.**		
PPL NERC Registered Affiliates	No	It is not clear to the PPL NERC Registered Affiliates why the SDT chose to use the loss of load (negative loss values included in the CERTS statistics) when determining the reportable threshold for BAL-002. The document fails to include the criteria that were used to define a "significant impact on frequency".
Response: Thank you for your comment. The drafting team has incorporated your comment and modified the standard.		
MISO Standards Collaborators	No	There first needs to be agreement on the requirements before there is concurrence with the background document.
Response: Thank you for your comment. The SDT would need additional information to provide a response. The SDT has made significant modifications to the standard and the Background Document,		
Southern Company: Southern Company Services, Inc.;	No	The Background Document states on page 4 that "FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or

Organization	Yes or No	Question 9 Comment
Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		contingency that causes a frequency deviation." We disagree with this interpretation of the Commission's directive. In Order 693 (P355) the Commission declined to define a 'significant deviation as a frequency deviation of 20 mHz', but instead directed the ERO 'to define a significant deviation and a reportable event'. The Commission directed that 'loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,' must be taken into account when developing the aforementioned definitions. We believe that the Commission clearly did not intend that any event that causes a frequency deviation, no matter how small, be included in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500 MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample. We question whether this is appropriate and believes that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method.We suggest that additional details be provided in the background document relating to the methodology for development of the reporting thresholds.
Response: Thank you for your comment. The SDT has modified the standard to accommodate your comment. **The SDT has modified the Background Document to provide additional clarity as to how the thresholds were developed.**		
ACES Standards Collaborators	No	(1) The background document needs to explain the conflict between BAL-002 and EOP-002 in detail rather than just stating that a conflict exists. (2) There is a statement on page 5 just before the Rationale by Requirement section that there are other definitions that have been added or modified. An explanation of what these are would be helpful.

Organization	Yes or No	Question 9 Comment
		(3) The formulas starting on page 8 are overly complicated in an attempt to address the few situations where there are additional generator contingencies that occur shortly before or during the ACE recovery window. We suggest starting with simple formulas that consider that predominant situation where only one generator contingency occurs. Then build the more complicated formulas on that. It will be easier to explain. We also suggest using pictures to explain the formulas. For example, a graph showing the loss of a unit before and after the current contingency would help explain the formulas. The graph should include labels such as what ACE_BEST, ACE_PRE, and MEAS_CR_RESP are.
Response: Thank you for your comment. **1 & 2 - The drafting team has modified the background document attempting to address your issues.** **3 - The SDT understands your concern and that is why they have provided a spreadsheet to assist you in the calculation.**		
IRC-SRC	No	There first needs to be agreement on the requirements before there is concurrence with the background document.
Response: Thank you for your comment. The SDT would need additional information to provide a response. The SDT has made significant modifications to the standard and the Background Document.		
PJM Interconnection, LLC	No	The Background Document states on page 4 that "FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation." PJM disagrees with this interpretation of the Commission's directive. In Order 693 (P355) the Commission declined to define a 'significant deviation as a frequency deviation of 20 mHz', but instead directed the ERO 'to define a significant deviation and a reportable event'. The Commission directed that 'loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,' must be taken into account when developing the aforementioned definitions. PJM believes that the Commission clearly did not intend that any event that causes a frequency deviation, not matter

Organization	Yes or No	Question 9 Comment
		how small, be included in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample, skewing the results. PJM believes that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method.
Response: Thank you for your comment. The SDT has modified the standard to accommodate your comment. **The SDT has modified the Background Document to provide additional clarity as to how the thresholds were developed.**		
American Electric Power	No	It is unclear whether or not the guidance document will eventually become a part of the officially posted standard (in an appendix for example).
Response: Thank you for your comment. The Background Document will not be a part of the standard. The spreadsheet that the SDT has developed will be part of the standard.		
Texas Reliability Entity	No	The equations and methodology on CR Form 1 seem flawed. The recovery requirement in R1 is based on ACE, but the calculations in CR Form 1 are based on the MW lost. We believe the equations in CR Form 1 and the Background Document should be modified to incorporate the elements of the ACE equation into the calculations (i.e. frequency deviation and frequency bias in particular). For example, a recent unit trip of 1300 MW occurred. Based on the frequency deviation, the lowest ACE during the one-minute event period was -1900 MW. The language of the requirement and the CR Form 1 should reflect the recovery of the ACE (1900 MW) rather than the MW lost (1300 MW) in this case.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. The SDT discussed this relationship between frequency bias and ACE. In your example we believe the additional 600 MW of ACE deflection is due to the delta in your actual frequency response and the frequency bias in the ACE equation. As the MW's lost is replaced by deployment of contingency reserves, the frequency would return back toward 60 hz which would assist in returning ACE toward 0. The MW's lost is the amount of contingency reserves that need to be deployed to restore balance to the interconnection. The measurement of recovery from a loss is still best reflected in ACE.		
Keen Resources Ltd.	No	The definition of "Best ACE" is unclear as: the "most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)". The meaning of "if any" is specified only in the attached spreadsheet that makes "claiming" such a subsequent event "optional" to the BA. In other words, a BA will not claim a subsequent event that makes the BA's compliance worse. The purpose of this definition of "Best ACE" is to prevent R1's sanctioning a BA's avoiding non-compliance due to insufficient reserve, by incurring a subsequent contingency within the recovery period to reduce the BA's recovery requirement. By this definition of "Best ACE" a BA will not claim a subsequent event that makes the BA's compliance worse. A clearer alternative definition of "Best ACE", that does not require the "optionality" obscurely lodged in the spreadsheet and that would harmonize with the needed change to the R1 wording that I show in my Comment to Question 10, would be "the least negative value if there are no positive values, or the most positive value of any positive values, among the values of ACE occurring during the recovery period, unless it is the ACE to which the addition of any subsequent events that occurred prior to or concurrently with it results in a value that is the least negative value if there are no positive values, or the most positive value of any positive values, among all such resultant values and the other ACE values during the recovery period."
Response: Thank you for your comment. The SDT discussed your proposed method during the drafting of the standard but chose to not pursue this due to the complexities involved.		
Tucson Electric Power	Yes	very helpful

Organization	Yes or No	Question 9 Comment
Manitoba Hydro	Yes	No comment.

NERC

10. **If you are not in support of this draft standard, what modifications do you believe need to be made in order for you to support the standard? Please list the issues and your proposed solution to the issue.**

Summary Consideration: Several commenters disagreed with the use of 500 MW as a threshold for reporting a disturbance for all Interconnections. The SDT modified the threshold to use a value unique to each Interconnection.

Many commenters question why the SDT was not using the term Reportable Disturbance. The SDT explained that the term Disturbance as defined by the NERC Glossary of Terms is extremely broad and not specific. The term Balancing Contingency Event was defined to allow the SDT to be more specific as to what should be considered for purposes of this standard.

Some commenters were confused as to how to calculate a Reserve Sharing Group Reporting ACE. The SDT modified the definition to state that it was the algebraic sum of the BAs participating at the time of the event Reporting ACEs or equivalent.

A few commenters stated that BAAL would handle Balancing Contingency Events and therefore this standard was not necessary. The SDT explained that they agreed that BAAL would handle DCS within a 30 minute interval as it was voted on back in 2007. However, elimination of BAL-002 has not been supported by the industry in the past.

Several commenters believed that there should only be two requirements in the standard, recover from a reportable event and replenish reserves. The SDT explained that they had preserved the two requirements that were identified within Requirement R1 and R2. In addition, the proposed Requirement R2 preserves the existing requirement to maintain reserve equal to MSSC (present Requirement R3.1).

A couple of commenters wanted the SDT to use BAAL as the measure for performance in this standard. The SDT stated that they considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.

Organization	Yes or No	Question 10 Comment
ACES Standards Collaborators		(1) We cannot support a 500 MW threshold for a Reportable Balancing Contingency

Organization	Yes or No	Question 10 Comment
		Event. The number is arbitrary without any technical justification. The background document explains how the drafting team reviewed CERTS data to arrive at the conclusion that a 100 MW threshold would cover all frequency events. Correctly, the drafting team determined that this was simply an unrealistic threshold and would not provide any additional reliability value. The background document then explains that the drafting team decided "to capture the majority of events having significant impact on frequency" by setting the threshold to 80% of the MSSC or 500 MW. It did not explain which value would do this or why it was important "to capture the majority of events". Furthermore, there is no explanation why 500 MW is necessary when today 80% of MSSC is used. Has the use of 80% of MSSC resulted in an unreliable system? Thus, we can only conclude the value is arbitrary. Please remove the 500 MW value. (2) Additional justification is necessary to change the pre-disturbance calculation from an average of 10 to 60 seconds of ACE data prior to the disturbance to a 16-second interval. There is no explanation of this in the background document and we cannot support such a change without a justification for how it supports reliability. Furthermore, it is not consistent with BAL-005-0.2b which requires ACE calculation on at least a six second basis. A BA using a six-second sample rate could be viewed as being out of compliance if they used either two (12 seconds) or three (18 seconds) samples since they cannot use exactly 16 seconds of data. Furthermore, using only two or three samples could lead to unrealistic averages particularly if there are any glitches in the data. What does an entity do if a scan was skipped or there was a data spike? More samples would make it less likely for this to be an issue. (3) The purpose needs to be modified. Please strike "balances resources and demand and". The purpose of the standard is to recover ACE following a Reportable Balancing Contingency Event. The portion that needs to be struck is addressed by BAL-001. (4) The drafting team has an opportunity to assist NERC in moving the Reliability Assurance Initiative along and showing some of the first fruits of the initiative. One

Organization	Yes or No	Question 10 Comment
		of the key white papers written for the initiative focuses on the reducing the data requirements and retention periods necessary for the compliance and enforcement process. NERC compliance has a stated goal of reducing the data retention burden on registered entities. The data retention required for the current versions of this standard exceed what is necessary and this draft version perpetuates the problem. All BAs currently must submit monthly data to their regional entities for this standard which clearly shows whether they are compliant or not. Then they are still required to retain three years worth of data. Since the regional entities already have the data and know whether they are compliant or not, what reliability value does three years of data provide? None. The new version will only perpetuate this issue. In response to our previous comments, the drafting team indicated that the monthly reporting is not required by the standard and is up to the region. While this is true, it is highly unlikely that the regional entities will change this monthly reporting burden given that the standard is conceptually the same as the existing standard. Furthermore, the drafting team and NERC staff can review the issue with regional entity compliance personnel to confirm their plans for monthly reporting. If they do plan to continue with the monthly reporting, then no more than six months of data is necessary and we request that the standard should be changed. It will demonstrate a good faith effort on the part of NERC to move the RAI forward. (5) The data retention section is inconsistent with the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C - Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Since a BA is on a three-year audit cycle, the period from the previous audit will be about 3 years. It could be a little more or a little less. However, the data retention section of "the current year, plus three previous calendar years" (which could be up to four years) actually could exceed this three year audit cycle period. Consider if a BA completed their last audit on November 15, 2010. Their audit cycle would require another audit in 2013. Let's assume this is scheduled for December 15, 2013. This means the audit period is 3 years and 1 month. It also means per the Rules of Procedure that NERC

Organization	Yes or No	Question 10 Comment
		cannot review any period prior to November 15, 2010 for compliance unless there is an outstanding investigation. Per the data retention section, on December 15, 2013, the date of the audit, the BA would have to retain data for all of 2013 as well as all of the data for 2010, 2011 and 2012. By the Rules of Procedure, the auditors could not review any data prior to November 15, 2010. Thus, the registered entity would be compelled to retain for 11.5 months for which NERC is not allowed to review. How does this benefit reliability? The data retention period should be changed to retain data since the last audit. Changing the data retention period to be no longer than since the last audit would show a good faith effort in moving the RAI along. (6) The VSLs for Requirement R2 need to be justified. There is no explanation provided for the values chosen for the various thresholds. For example, the Lower VSL covers contingency deficiency for a period of 5 to 15 hours. Why shouldn't this go to 20, 30, 40 or any other number of hours? Without a justification, we can only assume the numbers were selected arbitrarily. We are also confused by the Lower VSL since it starts at 5 hours. Does this mean that a BA can be deficient of contingency reserves up to 5 hours without a violation occurring? (7) There is no explanation for why Reportable Disturbance is not a satisfactory definition as used in the existing standard and why it is replaced with Reportable Balancing Contingency Event. Furthermore, it is not proposed to be retired. If the term will no longer be used, it should be retired. (8) Thank you for the opportunity to comment.

Response: Thank you for your comment.

1) The SDT has modified the standard to provide individual interconnection reporting thresholds.
2) The change from 10 to 60 with 4 scans to the 16 seconds prior to event was meant to clarify the pre-event data and provide consistency with BAL-003-1. The SDT has modified the Background Document to provide additional clarity.
3) The Purpose Statement does reflect recovery of ACE since ACE recovery is intended to provide the necessary indication to assure the balancing of resource and demand.
4) & 5) The SDT does not have control over what the regions require for reporting. The SDT believes that your comment is outside

Organization	Yes or No	Question 10 Comment
the scope of the drafting team. **6) The SDT agrees that the selection of 5 hours could be considered arbitrary and is based on the judgment of the SDT. The SDT has modified the requirement and the Background Document to provide consistency and additional clarity.** **7) The term Disturbance as defined by the NERC Glossary of Terms is extremely broad and not specific. The term Balancing Contingency Event was defined to allow the SDT to be more specific as to what should be considered for purposes of this standard. We have addressed the term Reportable by providing individual interconnection thresholds. The term Reportable Disturbance is presently used in other standards and therefore cannot be retired at this time.**		
Texas Reliability Entity		1) In ERCOT, we have an existing process in place to analyze unit trips greater than 500MW. However, other interconnections may find it overly burdensome to analyze these unit trips based on their current size and loads. 2) R1, as stated, is an event-by-event obligation. A failure to recover for one event would constitute a violation, even though the Responsible Entity may have performed well for the remainder of the period. Is this the intent of the SDT? Would the SDT consider another measure, such as evaluation of multiple events on a quarterly basis? 3) Does the SDT intend to retire the existing "Disturbance Control Standard" definition? Do you need to modify definition of "Reserve Sharing Group" to not reflect usage of "Disturbance Control Performance"? 4) The Reserve Sharing Group Reporting ACE definition is different here than the Regulation Reserve Sharing Group Reporting ACE definition provided in BAL-001-2, which is correct? (i.e. Does not have "at the time of measurement" as last part of sentence). 5) How do you calculate a Reserve Sharing Group Pre-Reportable Contingency Event ACE Value? We assume it is the algebraic sum of the ACEs of the BAs that make up the Reserve Sharing Group, but it may need to be explicitly stated.
Response: Thank you for your comment. **1) The SDT has modified the standard to provide individual interconnection reporting thresholds.**		

Organization	Yes or No	Question 10 Comment
2) Currently, in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base. 3) The SDT has modified the standard to eliminate the need to retire the existing Disturbance Control Standard definition or modify the definition for Reserve Sharing Group. 4) The SDT has made the necessary corrections. 5) The SDT has modified the definition for Reserve Sharing Group Reporting ACE to be the algebraic sum of the Reporting ACEs or equivalent.		
Modesto Irrigation District		A technical justification for the "16 second interval" for ACE and the "105 minutes" value for Contingency Reserve demonstration needs to be added.
Response: Thank you for your comment. The background document has been modified to include a discussion on the 16 second interval. The 105 minutes is the current time for DCS and comes from the 15 minutes of the event and the 90 recovery period.		
Duke Energy		o As the BAAL proposed in BAL-001-2 will address the loss of any resource, or any other change in ACE causing a Balancing Authority to exceed its BAAL, it could be argued that there is no reliability need to retain DCS. In 2007, the NERC Operating Committee supported the adoption of the BAAL and a subsequent field trial of operating without DCS to determine if the Standard was still needed. Until more experience is gained under the BAAL, Duke Energy supports having a Standard driving a Balancing Authority to address the largest of its events as it does today, however we see no reliability need to expand BAL-002 beyond the simple concept of measuring the recovery to the largest of the BA's resource losses - 80% or greater of the MSSC, and limited to MSSC, where the applicable events are clearly understood by the operator. Duke Energy disagrees with applying compliance and associated compliance reporting on an event-by-event basis, rather than allowing the quarterly reporting currently provided under BAL-002. The measures for compliance should recognize that no technical basis has been provided to support the 15-minute recovery required under Requirement R1 - compliance to a line drawn in the sand can be measured on a quarterly basis similar to today, as real-time reliability needs will

Organization	Yes or No	Question 10 Comment
		be met by the BA being held to compliance under BAAL. o Duke Energy disagrees with the definition of "Reportable Balancing Contingency Event". Given that all resource losses will be captured by the BAAL under BAL-001-2, that there is no basis for using 500 MW as a baseline for reporting, and that there has not been a demonstrated reliability need to move away from our current reporting criteria of 80% or greater of the MSSC, Duke Energy does not support the inclusion of the 500 MW threshold in the definition.. We believe that BAAL 30-minute response covers all events, and DCS action is a 15-minute response intended to address large events. We agree with MISO's comment that currently DCS is measured quarterly, and the proposed Requirement R1 creates an unnecessary event-by-event compliance evaluation. Adding the 500 MW threshold and multi-contingent event expectation is excessive, with no benefit to reliability. o Duke Energy believes that Reserve Sharing Group should have the flexibility to calculate a group ACE rather than just taking the algebraic sum of all the BA ACEs.
Response: The BARC SDT acknowledges that BAAL would handle DCS within a 30 minute interval as it was voted on back in 2007. However, elimination of BAL-002 has not been supported by the industry in the past. In addition, currently in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base. **The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **The SDT has modified the definition for Reserve Sharing Group Reporting ACE to be the algebraic sum of the Reporting ACEs or equivalent.**		
Manitoba Hydro		Although Manitoba Hydro is in support of this standard, we have the following clarifying comments: (1) Definitions, Reportable Balancing Contingency Event - there is no definition within the standard or Glossary as to what 'EMS scan rate data' is.

Organization	Yes or No	Question 10 Comment
		(2) Definitions, Contingency Event Recovery Period - the definition does not clearly define exactly when the Contingency Event Recovery Period begins. As written, the definition seems to indicate that this period begins at two different times (i) when the resource output begins to decline and (ii) in the first one minute interval of a Balancing Contingency Event. Please clarify. (3) Section D, Compliance, 1.1 - the paraphrased definition of 'Compliance Enforcement Authority' from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? (4) 1. (Proposed) Effective Date in both Standard and Implementation Plan - remove the " ' " following the word 'Trustees' because it is not defined this way in the Glossary of Terms. (5) R1 - as written, R1 requires that the Responsible Entity demonstrate that ACE was returned to a certain value. The demonstrate aspect of the requirement seems more of a measure than a requirement. In other words, the requirement should be that the Responsible Entity return the ACE to a certain value, the measure is that they provide evidence to demonstrate that they did so. (6) R1, R2 - both 'MSSC' and 'Most Severe Single Contingency (MSSC)' are used throughout the standard. The words 'Most Severe Single Contingency (MSSC)' should be used at the first instance and then the acronym 'MSSC' for all instances thereafter. (7) R2 - some of the terminology appears to be incorrect within this requirement. Is 'Disturbance Recovery Period' meant to be 'Contingency Event Recovery Period'? Is 'Contingency Reserve Recovery Period' meant to be 'Contingency Reserve Restoration Period'? (8) M1 - the word 'including' should be replaced with 'as well as' if the 'additional documentation' that needs to be provided is in addition to the CR Form 1, not that the additional documentation forms part of the CR Form 1. (9) VRF/VSL - capitalize 'bulk electric system' in both the High Risk Requirement and

Organization	Yes or No	Question 10 Comment
		Medium Risk Requirement sections. (10) VSL, R1 - the language of the VSL does not track the language of the requirement or measure. The VSL refers to 'recovering from an event' while the requirement refers to returning ACE to a certain level. (11) VSL, R2 - the language of the VSL does not track the language of the requirement or measure. The VSL refers to calendar quarters, while the requirement and measure do not.

Response: Thank you for your comment.

1 – The SDT understands that the phrase "EMS scan rate data" is used in several other standards (i.e., BAL-005 and BAL-003-1) and is a commonly used term within the industry.

2 – The definition, as presently written, is very clear and is intended to be read as written. The Contingency Event Recovery Period begins at the time specified and is to be read as one entire clause which is why it is not otherwise punctuated. In other words, the phrasing should not be broken into two parts.

3 – The language that is being used in this draft of the standard is the latest NERC approved language for Compliance Enforcement Authority.

4 - The language that is being used in this draft of the standard is the latest NERC approved language for Effective Date.

5 – The SDT agrees with your comment and has made the necessary modifications.

6 – The SDT spelled the phrase out for clarity and emphasis.

7 – The SDT realized that the incorrect terms had been used in this posting. This has been corrected.

8 – The SDT has modified the measure to provide additional clarity.

9 – The SDT has corrected the error that you have identified.

10 – Recovery from an event is returning your ACE to the conditions defined in Requirement R1. Therefore, recovery is incorporated into satisfying R1.

11 – The SDT has modified the language used in Requirement R2.

Organization	Yes or No	Question 10 Comment
Florida Municipal Power Agency		BAL-002, R1 states that the Responsible Entity shall demonstrate that it returned its ACE to zero (less some modifiers); in other words, the standard requires ACE to be returned to an absolute number, without a tolerance. I believe this is not the intent of the SDT, that they probably meant zero or positive, or something like that; but, reading the requirement literally, I believe it would be difficult to prove compliance using integrated values for ACE that will likely not equal zero.
Response: Thank you for your comment. The SDT has modified the language in Requirement R1 to address your concern.		
MRO NERC Standards Review Forum		Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today's DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL are crafted, this is now an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team's SAR and the Order No. 693 directives. Recommend that each interconnection has a different MW level, due to the sheer size of each interconnection. As an Eastern Interconnection entity, we recommend 900 MW vise 500 MWs. The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. Our recommendations are: Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes).

Organization	Yes or No	Question 10 Comment
		Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency. o Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation. o The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA’s performance approaches non-compliance. The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority. The drafting team is proposing to continue to use only ACE under Requirement R1 as the measure of reliability in the determination of Balancing Authority or RSG compliance. As has been seen in actual operation, the current methodology can lead to and has caused RC directives to drop load when there was not a reliability issue, defined as a frequency concern or transmission line loading issue. ACE is not a primary measure of reliability, only equity. To remedy this deficiency in the proposed

Organization	Yes or No	Question 10 Comment
		standard, the drafting team should utilize the BAAL limit as a more appropriate measure of response to the sudden loss of generation, not pre-event ACE or zero, whichever is lower. As proposed by the NSRF, this does not do away with DCS as originally proposed under BAAL but would change the measure of compliance in the DCS process to a more appropriate, reliability based measure. The NSRF is also not proposing to change the 15-minute period in BAL-002 for a reportable event with this modification.
Response: Thank for your comments. 1. **The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** 2. **The SDT has preserved the two requirements that you have identified within Requirement R1 and R2. In addition, the proposed Requirement R2 preserves the existing requirement to maintain reserve equal to MSSC (present Requirement R3.1).** 3. **This standard is designed to measure performance of your contingency reserve for Balancing Contingency Events up to your MSSC. This does not relieve you from meeting all of the other NERC reliability standards during these events. While the SDT understands your concern about single contingencies greater than MSSC, the SDT has chosen to use a single pre-determined contingency as the basis for this standard since it is well defined within the industry.** 4. **The SDT agrees with the industry with regards to the need for BAL-013-1. The SDT has chosen to stop development on a Large Loss of Load standard (BAL-013-1) and believes that the loss of a large load is covered in BAL-001-2 Requirement R2 (BAAL).** 5. **The SDT is developing a Reserve Guideline for approval and posting by the NERC OC.** 6. **The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** 7. **The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.**		
MISO Standards Collaborators		Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today's DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL are crafted, this is now

Organization	Yes or No	Question 10 Comment
		an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team's SAR and the Order No. 693 directives.The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. A Contingency Reserve Policy Guideline document in conjunction with the recommendations below should be sufficient to meet the drafting team SARs and the directives: o Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes). o Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency. o Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation. Also BAL-001's RBC is a more effective way to meet the FERC directive for loss of load events. o The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that

Organization	Yes or No	Question 10 Comment
		Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA's performance approaches non-compliance. o The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority.
Response: Thank for your comments. **1. The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **2. The SDT has preserved the two requirements that you have identified within Requirement R1 and R2. In addition, the proposed Requirement R2 preserves the existing requirement to maintain reserve equal to MSSC (present Requirement R3.1).** **3. This standard is designed to measure performance of your contingency reserve for Balancing Contingency Events up to your MSSC. This does not relieve you from meeting all of the other NERC reliability standards during these events. While the SDT understands your concern about single contingencies greater than MSSC, the SDT has chosen to use a single pre-determined contingency as the basis for this standard since it is well defined within the industry.** **4. The SDT agrees with the industry with regards to the need for BAL-013-1. The SDT has chosen to stop development on a Large Loss of Load standard (BAL-013-1) and believes that the loss of a large load is covered in BAL-001-2 Requirement R2 (BAAL).** **5. The SDT is developing a Reserve Guideline for approval and posting by the NERC OC.** **6. The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.**		
IRC-SRC		Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today's DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL is crafted, this is now an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North

Organization	Yes or No	Question 10 Comment
		America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team's SAR and the Order No. 693 directives.The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. Our recommendation are: o Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes). o Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency. o Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation. o The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA's performance approaches non-compliance. o The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority.

Organization	Yes or No	Question 10 Comment
Response: Thank for your comments. 1. The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis. 2. The SDT has preserved the two requirements that you have identified within Requirement R1 and R2. In addition, the proposed Requirement R2 preserves the existing requirement to maintain reserve equal to MSSC (present Requirement R3.1). 3. This standard is designed to measure performance of your contingency reserve for Balancing Contingency Events up to your MSSC. This does not relieve you from meeting all of the other NERC reliability standards during these events. While the SDT understands your concern about single contingencies greater than MSSC, the SDT has chosen to use a single pre-determined contingency as the basis for this standard since it is well defined within the industry. 4. The SDT agrees with the industry with regards to the need for BAL-013-1. The SDT has chosen to stop development on a Large Loss of Load standard (BAL-013-1) and believes that the loss of a large load is covered in BAL-001-2 Requirement R2 (BAAL). 5. The SDT is developing a Reserve Guideline for approval and posting by the NERC OC. 6. The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.		
Bonneville Power Administration		BPA is in support of this standard.
Response: Thank you for your support.		
ERCOT		ERCOT ISO supports the intention of the standard BAL-002-2 R1 to restore ACE back to pre-disturbance ACE but not necessarily to zero or the pre-disturbance ACE. The ACE recovery goal should be pre-disturbance levels. Therefore, ERCOT suggests the SDT establish a (epsilon1*Frequency Bias*10) band around the pre-disturbance ACE or zero ACE, and, if during recovery ACE is recovered within this range, entities would be compliant. This structure of establishing a goal, but providing for a compliance "floor" based upon the proposed range, will achieve the desired reliability benefits while also providing a reasonable degree of flexibility for circumstances where recovery to the exact pre-disturbance level is difficult to achieve, and unnecessary to

Organization	Yes or No	Question 10 Comment
		ensure reliability. ERCOT ISO also suggests that the 500 MW threshold be removed from the definition of Reportable Balancing Contingency Event. This requirement would impose an undue burden. There is no reliability reason to require mandatory reporting for these smaller events. It will merely create an administrative obligation with no corresponding reliability benefits. For instance, currently ERCOT ISO would typically need to report less than five events annually, but this new standard would increase this reporting burden to over 50 each year (based upon 2012 disturbances), without any corresponding reliability benefits. Accordingly, this obligation should be removed.If the SDT elects not to remove the 500 MW threshold generally, ERCOT ISO suggests that the threshold be removed for single-BA Interconnections. The threshold for single-BA Interconnections should be established as 80 percent of the MSSC. ERCOT ISO is voting "yes", but has reservations as described above and requests that the SDT revise the standard accordingly.
Response: Thank you for your comment. **In response to your concern, the SDT has modified Requirement R1.** **The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.**		
NextEra Energy		Have the option also calculate ACE using the following formula: ACE = (NIA âˆ’ NIS) âˆ’ 10B (FA âˆ’ FS) - IME
Response: Thank you for your comment. In response to your concern, the SDT has modified the definition.		
Avista		I can support this draft standard with the clarifications requested in Question #1 above.

Organization	Yes or No	Question 10 Comment
Response: Thanks you for your support. Please refer to our response to your comments for Question #1.		
American Electric Power		In addition to the comments provided to the earlier questions above, AEP offers the following additional comments for consideration. AEP disagrees with the latest proposed definition of “Preâ€Reportable Contingency Event ACE Value”, which has been made ambiguous by the most recent modifications. What is the intent of the drafting team in modifying the definition in this way? If this definition were to be used, new tools would likely need to be developed in order to calculate the value in this manner, as the operators would now be required to continuously calculate the ACE value based on this new definition. The definition for, and application of, Contingency Event Recovery Period is unnecessarily complex, confusing, and likely unpractical in its application. For example, if a unit was taken out of service due to a controlled shut-down, the Real Time Operator’s most pressing responsibility is balancing load and generation. Requiring this person to use the proposed methodology to determine exactly the contingency event recovery period began would distract the Real Time Operator from their core balancing responsibilities. Rather than take this approach, we recommend retaining the existing way of determining when the recovery period begins, which is a more straightforward and reasonable approach. In addition, the definitions for Contingency Event Recovery Period and Contingency Reserve Restoration Period are quite similar and would most likely prove confusing to industry in their application. Taking a conditional-based approach across multiple standards does not serve the reliability of the bulk electric system, as it takes a straightforward concept, overly complicates it, and distracts Real Time Operators from the core reliability objectives.
Response: Thank you for your comment. **1 & 2 - The SDT had no intent of causing you to change how you determine your ACE today under the existing standard, however,**		

Organization	Yes or No	Question 10 Comment
they intended to provide the necessary flexibility for you to account for prior and subsequent Balancing Contingency Events during the defined period. In addition, the determination of the pre-contingent ACE was modified to be consistent with the direction of BAL-003-1 and to eliminate possible inconsistency in its determination. **3 – The SDT created the definitions to provide additional clarity and flexibility for the BAs.** **4 – The SDT does not understand your comment about "conditional based approach across multiple standards" and therefore would need additional information to provide a response.**		
PJM Interconnection, LLC		In R1 and R2, delete the language related to a Responsible Entity under an Energy Emergency Alert Level 2 or Level 3, for the following reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE - this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The "Applicability" section clearly states that the standard does not apply to an RE under an EEA. Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the "hard" criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening the interconnection - wouldn't this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. PJM appreciates the SDT's goal of drafting a continent-wide standard but disagrees with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, PJM believes that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500MW as an example, a loss of 500MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. PJM believes that this SDT

Organization	Yes or No	Question 10 Comment
		and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO's. The State of Reliability Report prepared annually by the NERC identifies "the triggers for significant frequency events" that are specific to each Interconnection (ALR1-12 Assessment). As previously stated, PJM respectfully suggests that the SDT give due consideration to redefining a Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. PJM believes this is one approach that could satisfy the directive set forth in Order 693.
Response: Thank you for your comment. **1 – The SDT understands your concern and has modified Requirement R1 and Requirement R2 accordingly.** **2 & 4 – The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **3- The SDT has modified the definition for Reporting Ace addressing your concern.**		
Portland General Electric Company		Portland General Eletric is supportive of this standard.

Organization	Yes or No	Question 10 Comment
Response: Thank you for your support.		
Seminole Electric Cooperative, Inc.		Provide flexibility for an RSG ACE to be calculated based on aggregate participants frequency bias and RSG interchange with non-participants.
Response: Thank you for your comment. The SDT has modified the definition to address your comment.		
ReliabilityFirst		ReliabilityFirst votes in the negative for this standards and offers the following for consideration: 1. Definition of Reportable Balancing Contingency Event: ReliabilityFirst does not agree with the inclusion of last sentence (i.e., The 80% threshold may be reduced upon written notification to the Regional Entity) within the definition. As written, the definition infers that there is an expectation that a Regional Entity may have to make a determination on whether to accept a reduction in the 80% threshold based upon the written notification. This is troublesome in two ways. One, this is written more like a requirement, though it is actually contained within a definition. Two, standards should not be written with expectation placed upon a non-registered entity (i.e., the Regional Entity). ReliabilityFirst recommends removing this last sentence and any reference to the Regional Entity. 2. Applicability Section - ReliabilityFirst recommends removing the paragraph stating “Applicability is determined on an individual event basis...” from the Applicability section. The Applicability section should state the functional entity that is required to comply with the standard and the requirements should state any conditions necessary to achieve the action or outcome.
Response: Thank you for your comment. **1 – The definition does not put a requirement on the Regional Entity. The definition simply requires the Regional Entity to be notified.** **2 – The individual event basis was included to allow for the flexibility for individual BAs participating in a Reserve Sharing Group**		

Organization	Yes or No	Question 10 Comment
but opting out of the group for an individual event basis in accordance with the respective Reserve Sharing Group agreement.		
Oklahoma Gas & Electric		Remove the 500 MW threshold in the definition of Reportable Balancing Contingency Event
Response: Thank you for your comment. The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.		
seattle city light		Seattle City Light supports the general concepts of this draft of BAL-002-2, but as with BAL-001-2, Seattle thinks this draft needs more work and should not be implemented as currently written. It appears to have been rushed. Several specific recommendations for changes have been noted above. However, at least until the Guidelines document is available that details how this Standard will work in conjunction with other BAL Standards, Seattle cannot support this draft.
Response: Thank you for your comment. The SDT is presently working on the Reserve Policy Guideline document. The SDT will be presenting the draft Guideline document to the NERC OC for their acceptance at their September 2013 meeting.		
Tacoma Power		Tacoma Power appreciates the opportunity to provide comments. We cannot support this draft of the standard because we are unfamiliar with the phrase, "... known load used as a resource ..." in the definition of a Balancing Contingency Event. Therefore, this phrase must be defined or replaced so that there is no confusion within the industry and compliance authorities. We suggest using the phrase, "... interruptible load claimed as available reserves ...," which is Tacoma Power's interpretation. In addition, the VSLs are very confusing. All levels state that the Responsible Entity recovered from the event, yet they recovered to less than 100% of the required recovery. How can it be "recovered" without reaching 100%? Instead, we suggest that the VSLs recognize that the Responsible Entity "partially recovered" from the event.

Organization	Yes or No	Question 10 Comment
Response: Thank you for your comment. **The SDT has modified the definition to address concerns from the industry.** **The SDT has modified the VSLs for Requirement R1 based on comments from the industry.**		
Energy Mark, Inc.		The definition of "Pre-reportable Contingency Event ACE Value" should be modified as follows:The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is. I would strongly suggest that the wording for Requirement 1 should be modified to read as follows:R1. Except when an Energy Emergency Alert Level 2 or Level 3 is in effect, the ResponsibleEntity experiencing a Reportable Balancing Contingency Event shall demonstrate thatwithin the Contingency Event Recovery Period the Responsible Entity returned its Reportable ACEto: [Violation Risk Factor: Medium][Time Horizon: Realâ€time Operations]ï,· Zero, (if its Preâ€Reportable Contingency Event ACE Value was positive or equal tozero):o less the sum of the magnitudes of all subsequent Balancing ContingencyEvents that occur prior to that value of Reportable ACE within the Contingency Event Recovery Period, ando Further reduced by the magnitude of the difference between (i) theResponsible Entity’s Most Severe Single Contingency (MSSC) and (ii) the sumof the magnitudes of the Reportable Balancing Contingency Event and allprevious Balancing Contingency Events that have not completed theirContingency Event Restoration Period when the sum referenced in clause (ii)of this bullet is greater than MSSC,Or,ï,· Its Preâ€Reportable Contingency Event ACE Value, (if its Preâ€ Reportable Contingency Event ACE Value was negative),o less the sum of the magnitudes of all subsequent Balancing ContingencyEvents that occur prior to that value of Reportable ACE within the Contingency Event Recovery Period, ando Further reduced by the magnitude of the difference between (i) theResponsible Entity’s Most Severe Single Contingency (MSSC) and (ii) the sumof the magnitudes of the Reportable Balancing Contingency Event and allprevious Balancing Contingency Events that have not completed

Organization	Yes or No	Question 10 Comment
		theirContingency Event Restoration Period when the sum referenced in clause (ii)of this bullet is greater than MSSC.
Response: Thank you for your comment. **The SDT has modified the definition of Reporting ACE based on comments from the industry.** **The SDT has modified Requirement R1 to address your comment.**		
Xcel Energy		The drafting team is proposing to continue to use only ACE under Requirement R1 as the measure of reliability in the determination of Balancing Authority or RSG compliance. As has been seen in actual operation, the current methodology can lead to and has caused RC directives to drop load when there was not a reliability issue, defined as a frequency concern or transmission line loading issue. ACE is not a primary measure of reliability, only equity. Therefore, Xcel Energy is voting against the proposed standard. To remedy this deficiency in the proposed standard, the drafting team should utilize the BAAL limit as a more appropriate measure of response to the sudden loss of generation, not pre-event ACE or zero, whichever is lower. As proposed by Xcel Energy, this does not do away with DCS as originally proposed under BAAL but would change the measure of compliance in the DCS process to a more appropriate, reliability based measure. Xcel Energy is also not proposing to change the 15-minute period in BAL-002 for a reportable event with this modification.
Response: Thank you for your comment. The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve. The issue you have raised is outside the scope of this standard and should be resolved when IRO-005-4 is approved by FERC.		
PPL NERC Registered Affiliates		The PPL NERC Registered Affiliates offer the following comments: With respect to the proposed definitions, it is not clear why the SDT modified each of the proposed definitions but is only requesting input on a subset of the defined terms

Organization	Yes or No	Question 10 Comment
		during this comment period. With respect to requirement 1, it is suggested that the phrase “Except when an Energy Emergency Alert Level 2 or Level 3 is in effect,” be deleted for the following reasons: 1) An EEA in effect for any BA or RSG other than the responsible entity experiencing the contingency should not give the responsible entity an exemption from R1. For example, an EEA in effect for a BA in Florida should not be a consideration for the performance of a contingent responsible entity anywhere in the eastern interconnection. The language makes the assumption that both the EEA and contingency are affecting a single, specific responsible entity - if this is what the SDT intended, the language as currently written is too generic. 2) The Applicability section clearly states that the standard does not apply to a responsible entity under an EEA. If the SDT intends to include the exemption in the requirement language, it is suggest R1 is revised as follows: “Except when an Energy Emergency Alert Level 2 or Level 3 has been requested by the Responsible Entity, the Responsible Entity experiencing a Reportable ...” . Also, we suggest it would be more appropriate for the Responsible Entity to restore ACE to within the BAAL limits rather than the “hard” zero or pre-contingent ACE value within the 15 minute recovery period. Once a responsible entity has restored ACE within the BAAL limits it is no longer burdening the interconnection - this would be a sufficient recovery.We suggest that a successful response by the responsible entity would return ACE to the lesser of 0 or its real time BAAL limit (if its Pre-Reportable Contingency Event ACE was positive or equal to zero) and similarly - ACE returned to the lesser of its Pre-Reportable Contingency ACE Value or BAAL limit (if its Pre-Reportable Contingency Event ACE was negative). With respect to R2, it is not clear if responsible entity experiencing a non-reportable Balancing Contingency Event (i.e. a loss less than 500MW) is expected to maintain

Organization	Yes or No	Question 10 Comment
		Contingency Reserves at least equal to its MSSC. As currently written, it appears that R2 could require a Responsible Entity to always carry Contingency Reserves equal or greater than its MSSC plus 500MW (or its reportable threshold) so that Contingency Reserves will always exceed MSSC. With respect to measurement M2, it is not clear if Contingency Reserves may fall below MSSC for the first 105 minutes (Contingency Event Recovery Period plus Contingency Reserve Restoration Period) following any deployment of Contingency Reserves. If so, this may resolve the current expectation as written in R2. However, measures are not requirements and therefore, compliance is not judged through any potential flexibility provided in M2 or the VSLs. Requirement 2 (along with the currently effective version 1 of BAL-002) uses a capitalized term “Disturbance Recovery Period” that is not in the NERC Glossary of Terms. The SDT may have intended to use the term Contingency Event Recovery Period in lieu of Disturbance Recovery Period in requirement 2.

Response: Thank you for your comment.

1 – The SDT only asked questions when it made a significant modification. The SDT was not precluding anyone from providing a comment on any part of the standard through Question #10.

2 – The SDT understands your concern and has modified Requirement R1 and Requirement R2 accordingly.

3 - The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.

4 **– The SDT has modified Requirement R2 in response to concerns raised by the industry.**
5 **– An entity may deploy contingency reserve for any Balancing Contingency Event whether the event is reportable or not which provides you 105 minutes to restore your reserve.**

6 – The SDT has made the necessary correction for the error you identified.

Organization	Yes or No	Question 10 Comment
NV Energy		The Reportable Balancing Contingency Event definition lacks clarity. Are we to choose the higher of 500 MW vs. 80% of the MSSC or the lower of 500 MW vs. 80% of the MSSC? Seems like the measurement should be the higher of the two. 2. While I think I understand the goal of R1, to return ACE to zero neglecting other contingency events within the recovery period, the wording is very confusing. Expect misapplication of the standard with the existing wording. I suggest, for bullet #2: o Its Preâ€Reportable Contingency Event ACE, (if its Preâ€Reportable Contingency Event ACE was negative), o less the Balancing Contingency Events' magnitude summation for all subsequent events occurring within the Contingency Event Recovery Period, and o If the contingency event is greater than MSSC, further reduce the ACE recovery magnitude by difference between the Responsible Entity's MSSC and the uncompleted Balancing Contingency Events' magnitude summation.
Response: Thank you for your comment. **The reporting threshold would be the lower of either 80% of MSSC or the interconnection threshold.** **The individual event basis was included to allow for the flexibility for individual BAs participating in a Reserve Sharing Group but opting out of the group for an individual event basis in accordance with the respective Reserve Sharing Group agreement.**		
Keen Resources Ltd.		The wording of the recovery target ACE in Requirement 1 needs to be replaced as follows: "less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur WITHIN THE CONTINGENCY EVENT RECOVERY PERIOD [caps mine]" should be replaced by "less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur AT THE MOMENT OF RECOVERY (OR NEAREST-RECOVERY), or beforehand [caps mine]". Otherwise, by containing the word "all" in the selected wording, R1 sanctions a BA's avoiding non-compliance due to insufficient reserve, by incurring a subsequent contingency within the recovery period to reduce

Organization	Yes or No	Question 10 Comment
		the BA's recovery requirement. Furthermore, the current R1 definition contradicts the definition of "Best ACE" contained in the Background Document that was intended to preempt such BA behavior by defining "Best ACE" as: the "most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)". The meaning of "if any" is specified only in the attached spreadsheet that makes "claiming" such a subsequent event "optional" to the BA. In other words, a BA will not claim a subsequent event that makes the BA's compliance worse. A clearer alternative definition of "Best ACE", that does not require the "optionality" obscurely lodged in the spreadsheet and that would harmonize with the needed change to the R1 wording, would be "the least negative value if there are no positive values, or the most positive value of any positive values, among the values of ACE occurring during the recovery period, unless it is the ACE to which the addition of any subsequent events that occurred prior to or concurrently with it results in a value that is the least negative value if there are no positive values, or the most positive value of any positive values, among all such resultant values and the other ACE values during the recovery period.”
Response: Thank you for your comment. **The SDT understands your concern and has made modifications to Requirement R1 based on comments from the industry.** **The SDT discussed your proposed method during the drafting of the standard but chose to not pursue this due to the complexities involved.**		
SERC OC Standards Review Group		There is an embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn’t in the drafting team’s SAR or in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it’s

Organization	Yes or No	Question 10 Comment
		fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. We appreciate the SDT's goal of drafting a continent-wide standard but disagree with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, we believe that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500 MW as an example, a loss of 500 MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500 MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. We believe that this SDT and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO's. The State of Reliability Report prepared by the NERC identifies "the triggers for significant frequency events" that are specific to each Interconnection.We respectfully suggest that the SDT give due consideration to redefining a Balancing Contingency Event and Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. We believe this is one approach that could satisfy the directive set forth in Order 693. In R1 and R2, delete the language related to an RE under an Energy Emergency Alert

Organization	Yes or No	Question 10 Comment
		Level 2 or Level 3, for 2 reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. E.g. an EEA in effect for a BA in Florida should not be a consideration for the performance of a contingent RE anywhere in the EI. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE - this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The "Applicability" section clearly states that the standard does not apply to an RE under an EEA. Words could be added to R1 and R2 to clarify that the contingent RE is also the RE experiencing an EEA but a better solution is to simply delete the EEA related language from R1 and R2, Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the "hard" criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening the interconnection - wouldn't this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. We suggest that a successful response by the RE would return ACE to the lesser of 0 or its real time BAAL low limit (if its Pre-Reportable Contingency Event ACE was positive or equal to zero) and similarly - ACE returned to the lesser of its Pre-Reportable Contingency ACE Value or BAAL low limit (if its Pre-Reportable Contingency Event ACE was negative). If the interconnection frequency is high - why require a BA to increase generation more than is necessary to meet its BAAL low limit? If interconnection frequency is low, the BAAL low limit as well as the zero or pre-contingent ACE rule would still apply. These comments were also supporteed by Ron Carlsen with Southern Company. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review Group only and should not be construed

Organization	Yes or No	Question 10 Comment
		as the position of the SERC Reliability Corporation, or its board or its officers.
Response: Thank you for your comment. **1 – The SDT modified the existing standard by eliminating administrative requirements, however. they have maintained requirements associated with performance and addressed the FERC directive in order 693.** **2 & 3 – The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **4 - The SDT understands your concern and has modified Requirement R1 and Requirement R2 accordingly.** **5 - The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.**		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		There is an embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. We appreciate the SDT's goal of drafting a continent-wide standard but disagree with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, we believe that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500 MW as an example, a loss of 500 MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500 MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. We believe that this SDT and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all

Organization	Yes or No	Question 10 Comment
		Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO's. The State of Reliability Report prepared by the NERC identifies "the triggers for significant frequency events" that are specific to each Interconnection.We respectfully suggest that the SDT give due consideration to redefining a Balancing Contingency Event and Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. We believe this is one approach that could satisfy the directive set forth in Order 693.In R1 and R2, delete the language related to an RE under an Energy Emergency Alert Level 2 or Level 3, for 2 reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. E.g. an EEA in effect for a BA in Florida should not be a consideration for the performance of a contingent RE anywhere in the EI. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE - this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The "Applicability" section clearly states that the standard does not apply to an RE under an EEA. Words could be added to R1 and R2 to clarify that the contingent RE is also the RE experiencing an EEA but a better solution is to simply delete the EEA related language from R1 and R2,Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the "hard" criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening

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		the interconnection - wouldn't this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. We suggest that a successful response by the RE would return ACE to the lesser of 0 or its real time BAAL low limit (if its Pre-Reportable Contingency Event ACE was positive or equal to zero) and similarly - ACE returned to the lesser of its Pre-Reportable Contingency ACE Value or BAAL low limit (if its Pre-Reportable Contingency Event ACE was negative). If the interconnection frequency is high - why require a BA to increase generation more than is necessary to meet its BAAL low limit? If interconnection frequency is low, the BAAL low limit as well as the zero or pre-contingent ACE rule would still apply.
Response: : Thank you for your comment. **1 – The SDT modified the existing standard by eliminating administrative requirements however we have maintained requirements associated with performance and addressed the FERC directive in order 693.** **2 & 3 – The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **4 - The SDT understands your concern and has modified Requirement R1 and Requirement R2 accordingly.** **5 - The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.**		
Northeast Power Coodinating Council		There isn't an appropriate technical justification for requiring a 500 MW threshold. If the justification is simply to obtain more data samples, a 1600 data request is more appropriate than an enforceable Standard. Suggest reverting back to the 80% threshold which has thus far, shown to provide for an adequate level of reliability. The Standard can be simplified by replacing the existing requirements with ones that read: o recover from a Reportable Event within 15 minutes; o replenish reserves within 90 minutes.

Organization	Yes or No	Question 10 Comment
Response: Thank you for your comment. **The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis. In addition, the SDT is attempting to respond to the FERC directive to identify those events that can have a significant impact on frequency.** **At the core Requirement R1 does require recovery in 15 minutes. The additional qualifications allow for flexibility to address unusual circumstance that can arise.** **Requirement R2 provides for recovery of reserves within 90 minutes. The additional qualifications allow for flexibility to address unusual circumstances that can arise.**		
ISO New England Inc.		There isn't an appropriate technical justification for requiring a 500 MW threshold. If the justification is simply to obtain more data samples, a 1600 data request is more appropriate than an enforceable Standard. Suggest reverting back to the 80% threshold which has thus far, shown to provide for an adequate level of reliability.The Standard can be simplified by replacing the existing requirements with ones that read: o recover from a Reportable Event within 15 minutes; o replenish reserves within 90 minutes.As written, the Standard is overly complex.
Response: Thank you for your comment. **The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis. In addition, the SDT is attempting to respond to the FERC directive to identify those events that can have a significant impact on frequency.** **At the core Requirement R1 does require recovery in 15 minutes. The additional qualifications allow for flexibility to address unusual circumstance that can arise.** **Requirement R2 provides for recovery of reserves within 90 minutes. The additional qualifications allow for flexibility to address unusual circumstances that can arise.**		
Independent Electricity System Operator		We will support this standard, however please note the concerns expressed under Q2 and Q3, above, namely:

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		a. The last sentence in the definition for Contingency Reserve, and b. The need to define the term Reserve Sharing Group Reporting ACE (or the lack of explicit requirement for RSG to meet the DCS requirement).
Response: Thank you for your comment and support. Please refer to our response to your comments on Questions 2 and 3.		
Exelon		While we appreciate the work done since previous versions of the project, and recognize the clarity gained by eliminating reference to Balancing Contingency Events with a future impact to ACE, we feel that additional confusion has been inserted by the sub-points of R1. Given that the recovery requirement is a relatively short time-frame, the ability to quickly determine the recovery obligation is critical to the ability to ensure compliance. We appreciate that the drafting team is attempting to accommodate the notion that a prior Balancing Contingency Event might impact any future events, but the methodology given for determining the recovery threshold is overly complex, and represents a significant barrier to a system operator's ability to interpret the requirement in Real Time and respond appropriately.
Response: Thank you for your comment. The present BAL-002 has 16 requirements and sub-requirements. The SDT has reduced this down to two requirements, recover from a reportable event and ensure you have reserves.		

END OF REPORT