Consideration of Comments

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls
BAL-002-2

The Project 2010-14.1 standard drafting team thanks all commenters who submitted comments on the BAL-002-2 standard. The standard was posted for a 45-day public comment period from January 29, 2015 through March 18, 2015 (including a 2-day extension to reach quorum on the ballot). Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 24 responses, including comments from approximately 116 different people from approximately 80 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email, howard.gugel@nerc.net), or at (404) 446-9693. 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/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.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	Jason Marshall	ACES Standards Collaborators	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy	RFC	1
2.	Chip Koloini	Golden Spread Electric Cooperative	SPP	3, 5
3.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
4.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
5.	Steve McElhaney	South Mississippi Electric Power Association	SERC	1, 3, 4, 6
6.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
7.	John Shaver	Southwest Transmission Cooperative	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Phillip Hart	Associated Electric Cooperative, Inc.	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	entral Electric Power Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
2.	KAMO Electric Cooperative		SERC	1, 3								
3.	M & A Electric Power Cooperative		SERC	1, 3								
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3								
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3								
6.	Sho-Me Power Electric Cooperative		SERC	1, 3								
3. Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				
	Additional Member	Additional Organization	Region	Segment Selection								
1.	Dave Kirsch	Technical Operations	WECC	1								
2.	Bart McManus	Technical Operations	WECC	1								
3.	Fran Halpin	Duty Scheduling	WECC	1								
4. Group	Kelly Dash	Con Edison, Inc.	X		X		X	X				
	Additional Member	Additional Organization	Region	Segment Selection								
1.	Edward Bedder	Orange and Rockland Utilities	NPCC	NA								
5. Group	Colby Bellville	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								
6. Group	Carol Chinn	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.	Randy Hahn	Ocala Utility Services	FRCC	3								
6.	Stan Rzad	Keys Energy Services	FRCC	4								
7.	Don Cuevas	Beaches Energy Services	FRCC	1								
8.	Mark Schultz	City of Green Cove Springs	FRCC	3								
9.	Javier Cisneros	Fort Pierce Utility Authority	FRCC	4								

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

10.	Matt Culverhouse	City of Bartow	FRCC	3
11.	Tom Reedy	Florida Municipal Power Pool	FRCC	6
12.	Steven Lancaster	Beaches Energy Services	FRCC	3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Christina Bigelow	ERCOT	ERCOT	2
2.	Mark Holman	PJM	RFC	2
3.	Kathleen Goodman	ISO-NE	NPCC	2
4.	Greg Campoli	NYISO	NPCC	2
5.	Terry Bilke	MISO	MRO	2
6.	Ali Miremadi	CAISO	WECC	2
7.	Ben Li	IESO	NPCC	2

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph Depoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
2.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
3.	Chuck Lawrence	American Transmission Company	MRO	1
4.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
5.	Dan Inman	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6
6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
9.	Larry Heckert	Alliant Energy	MRO	4
10.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
11.	Marie Knox	Midwest ISO Inc.	MRO	2
12.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
13.	Randi Nyholm	Minnesota Power	MRO	1, 5
14.	Scott Nickels	Rochester Public Utilties	MRO	4
15.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6

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

17.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Guy Zito	Northeast Power Coordinating Council	X	X	X		X	X		X	X	X

Additional Member	Additional Organization	Region	Segment Selection	
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Helen Lainis	Independent Electricity System Operator	NPCC	2
11.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Paul Malozewski	Hydro One Networks Inc,	NPCC	1
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5

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

Additional Member	Additional Organization	Region	Segment Selection	
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	'Aine Hasham-Lawence	PPL Generation, LLC	RFC	5

NERC

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

4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			RFC	6
8.			SERC	6
9.			SPP	6
10.			WECC	6
11.			NPCC	6

				1	2	3	4	5	6	7	8	9	10
11.	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
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
12.	Group	Robert Rhodes	SPP Standards Review Group	X	X			X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Darryl Boggess	Western Farmers Electric Cooperative	SPP	1, 5
2.	Shannon Mickens	Southwest Power Pool	SPP	2
3.	Jason Smith	Southwest Power Pool	SPP	2
4.	Carl Stelly	Southwest Power Pool	SPP	2

				1	2	3	4	5	6	7	8	9	10
13.	Individual	Kristie Cocco	Arizona Public Service Company	X		X		X	X				
14.	Individual	Richard Vine	California ISO		X								
15.	Individual	Christina Bigelow	ERCOT		X								
16.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
17.	Individual	Leonard Kula	Independent Electricity System Operator		X								
18.	Individual	Kathleen Goodman	ISO New England		X								
19.	Individual	Terry Bilke	MISO		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Jared Shakespeare	Peak Reliability	X									
21.	Individual	Catherine Wesley	PJM Interconnection		X								
22.	Individual	Anthony Jablonski	ReliabilityFirst										X
23.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
24.	Individual	Pamela 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				

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

Summary Consideration:

Organization	Agree	Supporting Comments of "Entity Name"
California ISO	Agree	ISO/RTO Council Standards Review Committee
Hydro-Quebec TransEnergie	Agree	
ISO New England	Agree	NPCC RSC and IRC SRC
South Carolina Electric and Gas	Agree	PJM
ERCOT		ISO/RTO Council Standards Review Committee

1. Please provide any issues you have on this draft of the BAL-002-2 standard and a proposed solution.

Organization	Question 1 Comment
ACES Standards Collaborators	(1) The Most Severe Single Contingency definition and applicability section 4.1.1.1 should be modified to reflect that the standard simply applies to a BA or RSG by striking "that is not participating as a member of a RSG at the time of the event". This language may conflict with existing RSG contracts. Furthermore, it is a registration issue on whether the standard applies to the BA or RSG in these situations. When the RSG registers with NERC, NERC will typically review the contract to understand how the RSG is formed. If the standard should apply to the BA in certain situations and the RSG in others, this should be documented in a coordinated functional registration, not in a standards definition or applicability section. What does it even mean to be in "active status" under applicability section 4.1.1.1? 0 (2) Please strike the last sentence of the Reportable Balancing Contingency Event. It is administrative in nature and should be handled through compliance monitoring processes. If NERC wants to know if an entity has modified its reportable threshold, they have a myriad of compliance monitoring processes and tools to gather this information. It does not need to be documented in a glossary definition. Furthermore, it is not really a definition but rather an explanation and therefore, does not belong in the definition. (3) We continue to believe that the thresholds defined in the Reportable Balancing Contingency Event are arbitrary. We ask that the drafting team provide a technical basis for the values instead of the existing explanation in the Background document. While we understand that the drafting team reviewed some data, there are uncertainties regarding how values were identified from the data and then another value was selected. (4) We are confused about the "one-minute interval that defines a Balancing Contingency Event" language in the Contingency Event Recovery Period definition. We can find no reference to "one-minute" in the Balancing Contingency Event definition. There is, however, such a reference in the Reportable Balancing Contingency Event. Furthermore, the one-minute interval really does not define the event but rather pre-disturbance level

Organization	Question 1 Comment
	before the start of the event. The language in the Contingency Event Recovery Period needs to be cleaned up to reflect this information. The language of a Balancing Contingency Event should be broader than that in the Reportable Balancing Contingency Event. The Reportable group is a subset of the BCE. (5) We disagree with the definition of Contingency Reserve. The definition should be modified to simply reflect that Contingency Reserve Is unloaded on-line generation and quick start off-line generation capable of being dispatched in 15 minutes. The current definition may limit the use of Contingency Reserve and may omit off-line quick start generation since unloaded generation usually refers to on-line generators. The drafting team disagrees with this over-simplification of what is or can provide contingency reserve. However, the SDT modified the definition based on industry comments received. (6) Reportable Area Control Error in the Rationale box for R1 should be changed to Reporting ACE to match the NERC Glossary. The drafting team agrees with this comment and has made the modification. (7) The insertion of the "Reliability Coordinator approved" in Part 1.2 creates additional confusion by implying that an EEA can be issued without RC approval. An EEA cannot be issued without RC approval. Thus, this language is superfluous, only adds ambiguity and confusion to the part and should be struck. We disagree with the statement that the language makes the statement ambiguous. A Balancing Authority may request that the RC issue an EEA. The language was put in the requirement to clarify that the EEA must be approved by the Reliability Coordinator prior to the entity being excused from the requirement. If the EEA is not declared until after the 15 minutes, then the entity is not excused. However the SDT modified the definition and removed the language. (8) Although, we do not oppose the use of CR Form 1, Part 1.1 should be struck as it is administrative in nature. A violation of Part 1.1 could never result in a harm to reliability.

Organization	Question 1 Comment
	If an entity were to report the data in another format, reliability would not be harmed. If reliability cannot be harmed then a standard should not compel the action (in this case, specific use of a reporting form). Use of a CR Form 1 can and should be handled through NERC compliance monitoring processes as NERC and the Regional Entities do with other reporting formats and data collection methods. Use of CR Form 1 is already documented in the RSAW which should be sufficient. The SDT is attempting to provide for consistency in reporting. (9) While we appreciate that the drafting team did attempt to document other acceptable uses of Contingency Reserve in R2 that would not violate the requirement, we fundamentally disagree with the arbitrary selection of 90 minutes as a limit on the use of Contingency Reserve. Why should use of Contingency Reserve be limited to 90 minutes for an Energy Emergency? An Energy Emergency could last several hours and BA would be forced to either violate the requirement or shed load to avoid a compliance requirement. Neither is a good outcome. Rather, we suggest the 90 minute period should be dropped in Parts 2.1, 2.2, and 2.3. We particularly see this as an issue for Part 2.2. If an RC were to issue an Operating Instruction to use Contingency Reserve to resolve an EEA to avoid shedding load, why should this higher level authority not be able to instruct the BA to exceed the 90 minutes? The fact that Contingency Reserve may be used for longer than 90 is even documented in the second to last paragraph on page 36 of the background document. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan. (10) We disagree with the arbitrary selection of five minutes in Part 2.6 for the exemption to apply. We believe the five minutes is arbitrary and language is ambiguous which will only lead to inconsistent compliance outcomes. What would be considered preparations? Sending techs to the stations? Arming loading shedding schemes? Thinking about it? There needs additional clarification in the standard.

Organization	Question 1 Comment
	The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan (11) We disagree with the move from quarterly reporting to exception reporting. Today, compliance is assessed on a quarterly basis. This standard appears to require a Responsible Entity to issue a self-report anytime it does not recover 100% from a reportable a Reportable Balancing Contingency Event without any basis identified for the change. This will serve to increase a Responsible Entities compliance costs without any commensurate benefit to reliability. Furthermore, it will eliminate a data source that NERC uses for its annual state of reliability report which will be detrimental to the report. The SDT will work with NERC to ensure that they continue to get the necessary information for their reports and have that information added to the background document prior to the next posting. The individual event reporting moves the compliance process to meet the already used enforcement process. This also satisfies a FERC Order 693 directive. From Order 693 354. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters. (12) In Measure 2, we suggest adding a clause to the first bullet that Contingency Reserve must meet or exceed the required amount "unless one of the exceptions from R2 is met". The SDT has removed the language referenced.

Organization	Question 1 Comment
	(13) In Measure 2, we are confused by the language "excluded by rule in Requirement R2". Does this mean excluded by Parts 2.1 through 2.6? If so, change the language to "excluded by Parts 2.1, 2.2, 2.3, 2.4, 2.5 or 2.6". The SDT has removed the language referenced. (14) The VSLs for Requirement R2 should be modified to state that Responsible Entity did have less than the required amount of Contingency Reserve "and did not meet one of the exceptions in Parts 2.1 through 2.6". The SDT has modified the requirement and therefore made modified the VSL's accordingly. (15) We are concerned that the requirement formatting of the exceptions in Part 2.1 through 2.6 are not consistent with the informational filing NERC submitted to FERC several years ago regarding the use of bullets and parts in place of sub-requirements. In that filing, NERC stated that numbered lists or "Parts" would be used when all "Parts" must be met and "bullets" would be used when there are exceptions. To qualify for an exception, only one of the Parts 2.1-2.6 should be met not all. Yet, use of a numbered list implies that all exceptions must be met. The formatting needs to be modified to bullets instead of a numbered list. The SDT has modified the requirement.
PJM Interconnection	1. Please provide any issues you have on this draft of the BAL-002-2 standard and a proposed solution. 2. Comments: PJM appreciates and recognizes the work of the SDT as reflected in the present posting of the proposed BAL-002-2. PJM strongly urges the SDT to incorporate the following changes. 3. R1 Suggested changes:R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

Organization	Question 1 Comment
	o Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) (ii) by the magnitude of, each individual Balancing Contingency Eevent, or, o Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) (ii) by the magnitude of, each individual Balancing Contingency Event. 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved declared Energy Emergency Alert Level under which Contingency Reserves have been activated or depleted below reserve requirements. 1.3. Requirement R1 (in its entirety) does not apply: o (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or o (ii) after multiple Balancing Contingency Events and/or Contingency events that are not Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period, or o (iii) when the Responsible Entity is operating under the conditions described in R2, in its entirety.

Organization	Question 1 Comment
	R1 Discussion:PJM views it as necessary to include the MW losses associated with units that may ramp down or be derated which also result in a loss of output or capacity. CR Form 1 needs to be modified to account for the suggested changes in R1. The SDT has modified Requirement R1. If you look at the definition of Reportable Balancing Contingency Event, you will see that they are limited to events that occur within a one-minute time period. In your example, either the event would not be reportable if the runback goes for more than one minute, or the runback MWs would be used to adjust the ACE recovery for the Reportable event. Does CR Form 1 allow for loss of unloaded capacity? R2 Suggested changes:R2. The Responsible Entity shall develop and maintain an Operating Plan to procure Contingency Reserve capacity for each hour greater than or equal to its Most Severe Single Contingency for that hour. R2 Discussion:PJM urges incorporation of our suggested revision to R2. PJM would be supportive of a standard that incorporated our proposed revision. This revision recognizes that the procurement of Contingency Reserves is accomplished in the Operation Planning time horizon and that R2 as presently drafted is overly prescriptive. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan R2.6 Suggested Changes:Should the presently drafted R2 and associated sub-requirements remain in the standard, PJM believes R2.6 is not acceptable in its present language. A necessary revision would be as follows: R2.6. in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve. available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared.

Organization	Question 1 Comment
	The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan R2.6 Discussion:Load shedding plans are adequately addressed in the EOP standards. Requirement R2.6 as proposed is a distraction for the System Operator that has no positive impact on reliability. The requirement as written requires that Firm Load be shed to replace a shortfall of Contingency reserves. Why would an entity shed load to maintain reserves when shedding load via SCADA can be accomplished quicker than loading Contingency Reserves? The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan
ISO/RTO Council Standards Review Committee	1. The SRC generally supports R1. For clarity, and to address a concern that events that do not sudden as defined in the term "Balancing Contingency Event" (such as ramping, derating, etc.) are excluded from the recovery consideration, the SRC suggests the following minor clarification to R1 for consideration: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: o Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Contingency event that occurs shall reduce the required recovery: beginning at the time of, and by the magnitude of, each individual Contingency event, or, o It's Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Contingency event that occurs shall reduce the required recovery: beginning at the time of, and by the magnitude of, each individual Contingency event. (i.e., strike out (i) and (ii)) We further suggest Part 1.2 be revised to read: 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when:

Organization	Question 1 Comment
	o It is experiencing a Reliability Coordinator issued Energy Emergency Alert Level under which Contingency Reserves have been activated or deleted. o It experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan o It has experienced multiple Balancing Contingency Events and/or Contingency events that are not Balancing Contingency Events for which the combined MW loss exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. We disagree with this wording. Events greater than MSSC are excluded from R1 by definition of Reportable Balancing Contingency Event. 2. In our previous comments, the SRC stated that it found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met the requirement in R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. Note: ERCOT does not support this comment. The SDT has modified the requirement to have a process for Contingency Reserve in their Operating Plan 3. In addition, the proposed R2 has the following potential adverse consequences:

Organization	Question 1 Comment
	o An increase in reserves in order to maintain an amount over-and-above that required by the standard to meet non-DCS operational events, therefore, costing the rate payers additional monies for no increase in reliability (Note: IESO does not support this comment); The SDT has modified the requirement to have a process for Contingency Reserve in their Operating Plan o Operators not deploying reserves when needed for reliability in order to meet compliance with this requirement, which could be detrimental to reliability; and/or The SDT does not see any difference than what is currently required. o Entities shedding firm customer load to maintain reserves to meet compliance with this requirement, which, again, is not the right action to take for reliability. The SDT has modified the requirement to have a process for Contingency Reserve in their Operating Plan 4. We understand that the intent of the proposed R2 is to require a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 with the following: R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering other events that may reduce this amount. We believe this together with the recovery provision in R1 and the provision in Requirement R6 and Attachment 1 of EOP-011-1 would collectively take care of many of the conditions listed in the proposed Requirement R2 including active monitoring of the amount of reserve to meet the Contingency Reserve requirement. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs

Organization	Question 1 Comment
	thereby rendering a BA unable to meet requirement R1, then the following bulleted items may be added under Part 1.3 in R1: o When the Responsible Entity is using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) Note: ERCOT does not support this comment. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan.
Independent Electricity System Operator	1. In the last posting, we expressed a concern with the term "sudden loss" (see below). We are unable to find any response in the Summary Consideration report that addresses this comment. Please consider these comments and provide a response. A Balancing Contingency Event is vaguely defined as a "Sudden loss of generation..." or "sudden decline in ACE...". The word sudden is imprecise, and should be clarified. We suggest that the standard be clearer about defining the start time for a Reportable BCE. We support definitions like that used in NPCC Directory 5 section 5.17 where it says that the start of an event has occurred when a specific X amount of MWs are lost in a specific Y amount of time. Therefore, we suggest that the drafting team add precision in determining minute T+0 for an event by adding the following sentence (or something like it) to the Reportable BCE definition: "Following the resource failure, the Reportable BCE starting time is defined as the first chronological rolling one minute interval that meets the reduction in resource output(s) criteria stated herein." The SDT's response to comment does not appear to address this particular comment. We ask the SDT to please provide the rationale as to why this suggestion was not adopted. The term "sudden" is used in the definition of a wide category. This category may be used to refine the needed recovery for a Reportable Balancing Contingency Event under R1 in the proposed standard. The drafting team believes that as structured, the term "sudden" does not need further definition as any definitive definition would be somewhat arbitrary and possibly ill-fitting for one size entity while perfectly reasonable for another. While the example you provide works very well for the single entity that it covers, this type of structure is not likely to work for a nation-wide standard. The standard covers

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	entities such as relatively small Balancing Authorities like LADWP to very large entities such as PJM. Therefore a stated MW amount, or even a stated percentage would not treat all entities evenly or fairly. The drafting team supports the concept that each entity could provide further definition through written procedures to clarify how that entity implements their program. The drafting team disagrees with the need to add a sentence to the definition of Reportable BCE. The starting time of an event is determined by the definition of Pre-Reporting Contingency Event ACE Value. 2. In our previous comments, we found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met the requirement in R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. R2 as presented in this draft requires a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 with the following: R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering all other events that may reduce this amount. We believe this together with the recovery provision in R1 would take care of many of the conditions listed in the proposed Requirement R2. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs thereby rendering a BA unable to meet requirement R1, then the following bulleted items may be added under Part 1.3 in R1: o When the Responsible Entity is using its Contingency Reserve for a period not to

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	exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan.
Associated Electric Cooperative, Inc.	AECI respectfully requests that the SDT further consider modifying the Contingency Event Recovery Period to 30 minutes, or provide empirical evidence that demonstrates a risk to reliability exists when a Responsible Entity exceeds 15 minutes before recovering their ACE to the pre-disturbance level. Absent a risk to reliability when exceeding 15 minutes, the use of 30 minutes for the Contingency Event Recovery Period would more closely align with other reliability standards requirements that relate to operation of the BES during events, specifically the amount of time allowed for an entity to exceed an IROL. The existing standard requires 15 minute recovery for these events. The drafting team has not proposed to change the current recovery period. If the industry desires to change the recovery period to 30 minutes, studies would need to be made to determine the potential impact to reliability. The drafting team does not believe that a study can show less risk to the BES by extending the recovery period. It is unclear what could be shown to ensure that a longer recovery period would provide an Adequate Level of Reliability.
Con Edison, Inc.	Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material section: there is no substantial information contained in this section of the document. Is it the intent of the drafting team to fill-in these sections at a later date? If so, when would it be completed? If not, why not? This section may or may not be used in the standard. The SDT developed an Operating Reserve Guideline which could have been included in this section. However, the SDT decided to develop the guideline through the NERC Operating Committee. This allows for the guideline to be used for other standards and not just BAL-002.

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Arizona Public Service Company	APS would like the Drafting Team to clarify the following question about the draft language. R1.2 states "A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated." Since only a Balancing Authority can be declared to be in an RC-approved EEA, how would that impact the RSG that the Balancing Authority is a member of since that would be how they would be reporting their compliance with R1? Differently stated, does the RSG that the BA is a member of receive a waiver from R1 if the member BA is in an RC-approved EEA? If a Balancing Authority is experiencing an EEA event under which its contingency reserves have been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance. The RC should have gone through all steps prior to an EEA.
SPP Standards Review Group	BAL-002-2 Shouldn't 'transmission' as used in the definition of Balancing Contingency Event in A.a.iii. and B. be capitalized? Based on the drafting team's review of the defined term, we believe that the current term is more appropriate. Several standards recently have foregone the Effective Date section in the standard and instead refer to the Implementation Plan for the specific implementation dates. Should that be considered here? The SDT agrees and has made the necessary changes. Use lower case 'requirement' in the 3rd line of the Background material. (Did not look at this.) Contingency Reserve should probably be capitalized in the 1st, 2nd and 4th paragraphs of the Rationale Box for Requirement R2. The SDT has modified the requirement and therefore modified the rationale.

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	Delete the 's' on 'suites' in the 11th line of the 2nd paragraph of the Rationale Box for Requirement R2. The SDT has modified the requirement and therefore modified the rationale. Shouldn't 'load' be capitalized in the 4th paragraph of the Rationale Box for Requirement R2? The SDT has modified the requirement and therefore modified the rationale. Background Document Consistency is needed throughout the document in the capitalization of terms such as 'Transmission', 'Contingency Reserve', 'requirements', 'Transmission Line', 'Responsible Entity', 'Load', 'Real-time', 'energy deficient entities', 'event', 'field trials' and 'firm load'. In some situations, the SDT uses 'SDT' and in others it simply uses 'drafting team'. Be consistent throughout. Replace 'Balancing Authority or Reserve Sharing Group' with 'Balancing Authority (BA) or Reserve Sharing Group (RSG)' in the 9th line of the 3rd paragraph on Page 3. Subsequent uses of these terms should then be BA or RSG, respectively. Insert '(MSSC)' immediately following 'Most Severe Single Contingency' in the 2nd line of the 2nd paragraph on Page 4. Replace 'Standard' in the 6th line of the same paragraph with 'standards'. Replace 'the real-time operations' with 'Real-time operations' in the 1st line of the 1st paragraph under Balancing Contingency Event on Page 5. Replace 'requirement' with 'directive' in the last line of the 2nd paragraph under Balancing Contingency Event on Page 5.

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	Replace the 3rd bullet at the top of Page 7 with the following: 'resolving the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) that requires the use of Contingency Reserves; and'. Replace 'requirements' with 'directives' in the 4th line of the 4th paragraph on Page 9. Replace 'suites' with 'suite' in the 1st line in the 1st paragraph at the top of Page 10. The SDT is to be commended for the improved clarity in the examples in Attachment 2. The reference sited in the last line of the 2nd paragraph on Page 34 (Footnote 5) is not attached. It's referenced in Footnote 5. There is no Footnote 3 as referenced in the 3rd line of the paragraph under Control Performance Standards (CPS1) on Page 34. The SDT has reviewed the Background Document and believes that it has made all necessary corrections. CR Form 1 In cell A15 of the Read Me tab, use lower case 'it'. In cell A1 of the Exemption tab, replace 'Exemp' with 'Exempt'.In cells A10 and A16 of the Description tab, Â© appears instead of the intended (c). Thanks Microsoft. In cell A11 of the Entry Instructions tab, insert 'with' between 'associated' and 'subsequent'. In cell A4 of the Calculator tab, insert 'the' between 'Enter' and 'name'.
Bonneville Power Administration	BPA is in agreement with the proposed standard, however, believes there should be a clarifying comment in requirement R1. In R1, following both sub-bullets of R1, BPA would like to state:

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	”For all subsequent events that occur during the initial Contingency Event Recovery Period, the Pre-Reporting Contingency Event ACE Value for that initial event must be used for the subsequent event(s).” The SDT reviewed the requirement and determined that the present language sufficiently covered all situations. Finally, BPA proposes that R2 2.6 spells out that it only pertains to an EEA3. The reason for this is that exemption only applies to EEA level 3 in EOP-011-1 Emergency Operations. In that new standard, EEA 3 is defined, in part, as a situation where “The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.” EEA 2 language clearly states that while a BA can no longer meet all of its expected energy requirements: “An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.” The SDT has modified the requirement to have a process for Contingency Reserve in their Operating Plan.
ERCOT	ERCOT commends the drafting team on their efforts to improve BAL-002-2. However, it has concerns and recommendations regarding the proposed modifications. These concerns and recommendations are described below by Requirement. Proposed revisions are italicized. 1. Definitions - ERCOT reiterates its previous comments regarding the Reportable Balancing Contingency Event thresholds contained within the definition of a Reportable Balancing Contingency Event. ERCOT believes that the introduction of various, differing thresholds creates unnecessary complexity and would propose a 1000 MW threshold for its interconnection as such threshold aligns with the current practice. Further, ERCOT reports other, smaller events to NERC and its Regional Entity through different mechanisms and, therefore, with differing reporting thresholds, the same event can be reported to NERC multiple times under different requirements. Accordingly, since the threshold limits relate only to reporting and associated

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	documentation, ERCOT respectfully submits that lowering the reportable event thresholds does not provide any benefit to reliability. FERC Order 693 states that the standard should address events that impact frequency in the interconnection. Based on review of events over the last 5 years, the levels in the definition address this event. 2. Requirement R1 - Recommend modifying the addition (Reliability Coordinator Approved) to Reliability Coordinator Issued. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan 3. Requirement R1.2 and Requirement R1.3 - ERCOT recommends the consolidation of R1.2 and R1.3 and additional revisions as follows: 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when: o It is experiencing a Reliability Coordinator issued Energy Emergency Alert Level under which Contingency Reserves have been activated or depleted. o It experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency o It has experienced multiple Balancing Contingency Events for which the combined MW loss exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. ERCOT recommends modifications to subpart 1 regarding the depletion of contingency reserves because contingencies that deplete reserves can occur without formal “activation” of reserves and without a “sudden” or triggering event. Thus, it respectfully suggests that the requirement should be modified to ensure that acknowledgment of such reserve depletion.

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	The SDT has modified Requirement R1 and Requirement R2. ERCOT further recommends revision to subpart 1 because partially loaded generators may experience contingencies that remove MW from the BA, which may reduce the availability of reserves maintained by such resources as headroom. In such a circumstance, it is possible to have multiple contingencies where the MW loss is less than the MSSC, but that result in significant or complete reserve depletion for the BA. Accordingly, ERCOT recommends that subpart 3 be clarified to ensure that the loss to which the subpart would be applicable is clear and unambiguous. By accounting for overall MW of loss, not the magnitude of capacity loss, the applicability of Subpart 3 would be objective and easily discerned. 4. Requirement R2 -ERCOT respectfully submits that, as proposed, Requirement R2 would result in the unnecessary diversion of attention and resources during real-time operations to ensuring that data recordation and documentation occurred - rather than the performance of activities that are more directly associated with sustaining the reliability of the Bulk Electric System, e.g., contingency reserve mix, monitoring, deployments, etc. Accordingly, ERCOT respectfully suggests the following alternative revisions, which it believes more closely aligns with the Commission's directives: R2. The Responsible Entity shall plan to procure Contingency Reserve greater than or equal to its Most Severe Single Contingency, except during one or more of the following periods when the Responsible Entity is: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] 2.1 using its Contingency Reserve, for a period not to exceed 90 minutes, to mitigate the reliability concerns associated with Contingencies that are not Balancing Contingency Events; and/or 2.2 using its Contingency Reserve, for a period not to exceed 90 minutes, to respond to an Operating Instruction requiring the use of Contingency Reserve; and/or

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	2.3 using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) that requires the use of Contingency Reserve; and/or 2.4 in a Contingency Reserve Restoration Period; and/or 2.5 in a Contingency Event Recovery Period; and/or 2.6 in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared. Measure 2 could then be modified as follows: Compliance may be achieved by demonstrating that: o The Balancing Authority's Operating Procedures require procurement of Contingency Reserve amounts that meet or exceed the Contingency Reserve required to respond to its Most Severe Single Contingency; or, o Contingency Reserve has been restored to the required Contingency Reserve levels within the specified period; or, o the sum of the Contingency Reserve and Firm Load available as a substitute for unavailable Contingency Reserve reaches the required Contingency Reserve level within the specified period; Failure of the Balancing Authority to procure adequate Contingency Reserve to respond to its MSSC and/or recover the required Contingency Reserve level within the time periods prescribed would be considered an exception and should be reported quarterly.

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	ERCOT suggests this alternative because the directive being addressed required development of a continent wide contingency reserve policy, but did not require or prescribe tracking or reporting obligations. The proposed modifications appear to not only address a proposed reserve policy, but appear to also be revising the current quarterly reporting and prescribing an hourly tracking and recordation, actions and obligations for which ERCOT has been unable to identify an associated directive. Such additions will likely have unintended consequences in how Reserve Sharing Groups (RSG) will operate. In particular, the failure or delay of a contingency resource start can result in recovery performance that is assigned a very low score for that single event, even where recovery is only a minute or two late. Such outcome would be an inaccurate indicator of the overall success of the recovery, the overall recovery performance, and the Responsible Entity's efforts to recover. Further, there are RSGs whose purpose is to mitigate such risk by deploying reserves for much smaller events, helping reliability through quick recovery from smaller events, faster replenishment of reserves, and opportunity for operators to gain necessary experience regarding reserve deployment. Should each recovery event become individually sanctionable, RSGs will likely modify their rules to increase their reportable threshold to the interconnection minimum, which would reduce the net benefits to grid reliability discussed above. Additionally, the current quarterly reporting has provided an important data source that is used for NERC's RAPA group and the State of Reliability Report: http://www.nerc.com/pa/RAPA/ri/Pages/DCSEvents.aspx. The transition away from quarterly reporting to only exception reporting will eliminate that data source and reduce overall visibility. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan. The drafting team is aware of only one RSG that currently uses a reduced minimum reporting threshold for their DCS compliance process. The other side of the debate on individual event reporting versus quarterly reporting includes the following points: 1. The minimum requirement for compliance is 100 percent so any failure to respond causes a non-compliance. The question then is how is a fine determined? Should it be

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	based on the percentage of events for which compliance was/was not obtained, the percentage of failed response (i.e. total response needed for all events was 1,000, response received was 950) 2. Quarterly reporting averages can move based on the number of reportable events in a quarter, the size of reportable events or other variable that arguable have no bearing on the impact to the BES of an entity's failure to meet the response requirement. Depending on the answer to the first issue, this may or may not be a reasonable metric. Just because it has been used for compliance purposes, that does not mean it is a reasonable measure of reliability or impact to reliability. In the discussion of a slower than anticipated start of a unit, there is no clear reasoning for how a determination of violation one failure in the quarter is adequately represented. If we assume that the total response provided in the quarter divided by the total response required in the quarter, only the MWs failed to be delivered matters, not the amount of time afterwards. Therefore, an individual event evaluation provides for a much better means to determine the impact to reliability from a single failure as opposed to a quarterly mishmash of all events. The drafting team believes that while a quarterly report may provide good data for trend analysis, it is a poor means to determine compliance. The drafting team is working with NERC staff to develop a process by which the quarterly information would still be available for the reports cited. However, the drafting team recommends that this data collection effort be outside of and separate from the compliance process. To facilitate the identification of exceptions while maintaining the value and benefits associated with quarterly reporting, ERCOT recommends that there be a single quarterly report for all data collected. In such a report, the Requirement R1 portion would be very similar to the current reporting form with an additional portion where instances of reserve amounts that were less than the MSSC during the quarter could be reported. Such coordinated reporting would allow both the ERO and the industry to evaluate reserve and contingency data concurrently, providing the opportunity to identify any trends and/or dependencies.

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	The drafting team is working with NERC staff to develop a process by which the quarterly information would still be available for the reports cited. However, the drafting team recommends that this data collection effort be outside of and separate from the compliance process. ERCOT respectfully submits that the requirement to plan for and procure reserves greater than or equal to a BA's MSSC is an appropriate continent-wide contingency reserve policy and that such policy, when considered in coordination with obligations set forth within other approved reliability standards such as EOP-011-1 (Requirement R6) (EEA), IRO-005-3.1 (Requirement R2) (RC must monitor Con. Res., due to be retired when new IRO standards are approved), and TOP-002-2.1b (Requirements R5 - R8) (also due to be retired with new TOP standards, did not look for requirement mapping) are more than adequate to ensure reliability. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan Further, ERCOT would suggest that hourly calculation and/or demonstration of reserve amounts is: (1) not necessary when reserve requirements are considered in pari materia with other reliability standards obligations of BAs as described above, (2) unduly burdensome, and (3) a threat to reliability due to the diversion of resources that would be necessary to sustain compliance. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan. Quarterly reporting of Reportable Balancing Contingency Events along with the reporting of reserve amounts less than a BA's MSSC are more than sufficient for both the ERO and responsible BAs to identify and address contingency reserve issues that would threaten reliability. Hence, requiring BAs to provide documentation of contingency reserves

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	averaged over a clock hour is an onerous, purely administrative obligation that elevates documentation over reliability. Thus, ERCOT recommends that Requirement R2 be revised as set forth above. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan. ERCOT thanks you for the opportunity to comment upon the proposed Revisions to BAL-002-2 and respectfully suggests that, as NERC continues its effort to move away from zero defect standards, Requirement R2 be revised as recommended above to support that concept. Should the ERO wish to provide additional guidance regarding the mix or management of Contingency Reserves, it should consider the development and publication of a Reliability Guideline.
Florida Municipal Power Agency	FMPA supports the comments of Duke Energy
Duke Energy	General Comments: Duke Energy would like to take the opportunity to offer comment on the overall project concerning BAL-002-2 in conjunction with the recent FERC NOPR issued on November 20, 2014. FERC issued a NOPR proposing the approval of the BAL-001-2 standard (Real Power Balancing Control Performance). FERC commented in its NOPR that further revisions to the BAL-002 standard should take into consideration, the impact the revisions may have on the Balancing Authority ACE Limit (BAAL) in BAL-001-2. Duke Energy agrees with the Commission that the potential impact that compliance with BAL-002 may have on BAAL should be taken into consideration during further modifications to BAL-002, and suggests that this project be tabled until the final order issuing the approval of BAL-001-2 has been handed down by FERC. While we may agree with the premise, the current standard needs to be either replaced or retired sooner rather than later. This revision addressed the problems with the existing standard while keeping essentially the same thing in place. Balancing Contingency Event: Duke Energy would like to re-state its concerns with the proposed definition of Balancing Contingency Event. Originally, we stated that we sought

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	clarification on item B of the Balancing Contingency Event (BCE) definition. A BCE should be predicated on a deviation in Area Control Error (ACE) . As written, we are unclear why item B is even part of the definition because we believe Item B is redundant with item A.a.ii. We fail to see the additional clarity that Item B provides, and could see where questions could arise regarding the differences between the two items in the future. The SDT disagrees with this statement and feels that the present language is sufficient. Also, this comment does not appear to be supported by the majority of the industry. Background: In the revised background section of the proposed BAL-002-2, the section alludes to frequency management, however, we fail to see any requirement in this standard pertaining to frequency management. The SDT is not trying to say that BAL-002 provides frequency management. We are only pointing out that some parts of BAL-002 can influence frequency management. R1: We would like to offer our previous comment on this requirement for the drafting team's consideration. Duke Energy suggests the following revision to R1.2: "1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert under which Contingency Reserves have been utilized to serve load." We believe the intent of the SDT was for the Responsible Entity to be exempt from compliance with R1 during those instances where Contingency Reserves are utilized to serve load. Duke Energy requests further clarification on what is meant by the reference to activate Contingency Reserves under an Energy Emergency Alert (EEA). R1 Rationale: If the SDT's intent is to eliminate any potential overlap with other standards, this will not be the case once the BAAL is in place. If BAL-001-2 is approved, there will be another standard driving a BA to take corrective action when frequency is hurting. Again, we caution the SDT that moving forward with the BAL-002-2 project without taking into consideration the BAAL, could result in conflicting standards. In addition, we believe that there are situations where compliance with BAL-002 may have a detrimental impact on Interconnection frequency. For example, as the Disturbance Control Standard ("DCS") under BAL-002 is measured event-by-event, a Balancing Authority is required to return its

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	ACE to zero with 15-minutes after a Reportable Disturbance (or back to its pre-Disturbance ACE value if that value was negative). Such a response in the future may be a problem if the Reportable Disturbance occurs when frequency is above Scheduled Frequency, as over-response required by the Balancing Authority to ensure compliance with BAL-002 may cause the Balancing Authority to be above its high BAAL under BAL-001-2. If a generation resource was lost in the middle of the night during a period of minimum load concerns, numerous available generation resources, and high Interconnection frequency, BAAL would drive the Balancing Authority to take appropriate action over a reasonable timeframe. DCS would not consider any of these factors but would require the Balancing Authority to strictly comply. This strict compliance with BAL-002 could have a detrimental impact on Interconnection frequency. In the description of the EEA Level 3, it states that Contingency Reserves are being used to serve load. Your understanding of the intent is correct. The drafting team modified the language to provide clarity. R2: Duke Energy requests further clarification from the drafting team on whether its intent was for the standard to be worded in such a manner to allow for the waiving of immediate restoration of reserves. Is it the SDT's intent to afford an entity the opportunity to wait for a period of 90 minutes, before requiring the restoration of reserves to take place? As written, the auditable requirement is for reserves to be restored within 90 minutes. While the current language of the standard suggests it should be completed faster, the actual compliance check point is at 90 minutes. The SDT also added Requirement R3 to provide additional clarity. Also, Duke Energy suggests a re-ordering of the sub-requirements for R2. Sub-requirements 2.4 and 2.5 should be first and second on the list of sub-requirements based on the reasoning that they would be the most common instances. Regarding sub-requirement 2.6, we feel that clarifications are needed. As written currently, it is unclear whether an entity has to actually shed load for 2.6 to apply, or if you have to just be prepared to do so. There are concerns that requiring compliance

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	documentation to demonstrate that you were prepared to take some action, even though said action never took place, could be considered onerous. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan Lastly, upon our review, it could be argued that some of the sub-requirements appear to mirror closely responsibilities that are already present in EOP-002. We suggest that the SDT consider delaying implementation of BAL-002-2 so that it becomes effective after EOP-011-1. The SDT has modified the requirement to have a process for Contingency Reserve in their Operating Plan.
Peak Reliability	General: BAL standards should be developed as a group and not individually. R1.2: "A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated."EOP-002-3.1 speaks to the RC initiating/declaring but not approving an Energy Emergency Alert. It can be argued that parameters are in place to make a decision on approval but nevertheless there is no mention of approvals nor defined approval processes within the standard. Suggestion is to revise from "approved" to "initiated/declared" to remain consistent with EOP-002-3.1. The SDT has removed the language referenced and modified the requirement. R2: Peak is concerned that using an average clock hour might allow entities to take advantage. For example, if an entity is deficient the first 30 minutes but sufficient the second 30 minutes, the average clock hour would be met but the first 30 minutes would be in an unreliable state. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan

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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	In regards to R2.6: In an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared. Southern agrees that a BA should not be required to maintain Contingency Reserves during an applicable Energy Emergency Alert level (for Southern that would be an EEA3). Our concern is with how the following sentence is phrased "For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared." We recommend a different approach so that it reads, "For this exemption to apply, the deficient BA must be able to execute interruption of Firm Load to restore ACE within the Contingency Event Recovery Period timeframe". The rationale behind this change is if a deficient BA can recover ACE within Contingency Event Recovery Period via load shed this should be an acceptable practice but they must have the ability to execute completely this action within the Contingency Event Recovery Period timeframe (e.g. 15 minutes). Southern agrees with the drafting team that in an EEA3 a BA should be able to consider load shed as a viable practice to maintain ACE and not be required to re-establish Contingency Reserves by shedding load pre-contingency. The current way the Measure is worded supports this purposed change. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan
ReliabilityFirst	ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1 - ReliabilityFirst suggests using the word "shall" instead of "will" to make mandatory the use of the noted CR Form 1. The term "shall" indicates a duty on the subject and is used throughout the NERC Standards in this manner; in this case the responsible entity has a duty to use CR Form 1, so "shall" is the more appropriate term. ReliabilityFirst recommends attaching it to the standards along with

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	the following change for consideration: "The Responsible Entity shall document all Reportable Balancing Contingency Events using Attachment 1 - CR Form 1." The SDT is attempting to provide for consistency in reporting. 2. Measure M2 - The newly included second paragraph within Measure M2 reads more as an exception to the requirement and does not belong as a measure. It appears to be guidance to an auditor and should more appropriately be placed in an RSAW. Furthermore, ReliabilityFirst does not want to encourage missing data as a reason for not performing the calculation and believes any or as many valid samples of the Contingency Reserve should be included in the clock hour and should not be excluded from the evaluation. ReliabilityFirst recommends completely removing the second paragraph within Measure M2 from the standard. The SDT has modified the requirement and therefore made modified the measure accordingly.
Seattle City Light	Seattle City Light supports Balancing Authorities having the flexibility to use Contingency Reserve to respond to other reliability events and votes affirmative for this ballot. Seattle would support the draft more, however, if the term "clock hour average" was replaced with "instantaneous value" throughout the Standard. Using Hourly averages places entities in the position where they may be incentivized to have less Contingency Reserve than their current Most Single Severe Contingency for large percentages of key operating hours. From a financial perspective, there is nothing in this revision stopping a Balancing Authority from having less Contingency Reserves than their Most Single Severe Contingency during the last 20 to 30 minutes of every steep load pick up hour every day. While theoretically possible, this operating practice would subject an entity to violation of one or both requirements if an event occurs during the ramp period. (In other words, one bad day and it will never happen again.)

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Northeast Power Coordinating Council	There is a possible inconsistency in the terms Balancing Contingency Event, and Reportable Balancing Contingency Event. Balancing Contingency Event is defined as “Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute...” Reportable Balancing Contingency Event is defined as “...(ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE...” By its definition, the Balancing Contingency Event, in the extreme, is an unlimited number of single events, as long as they are separated by less than one minute. Is it intended for a Reportable Balancing Contingency Event to only encompass what happens in the first minute as it is worded? Yes, if an event takes longer than a minute to unfold, it makes the measurement process impossible. Therefore the standard only covers those events that meet the exact definition of Reportable BCE. The set of Balancing Contingency Events would by definition be either equal to or more than likely greater than the Reportable BCE set. In the NERC Glossary, Reportable Disturbance is defined as “Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority’s or reserve sharing group’s most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.” The definition of Reportable Balancing Contingency Event should be revised to incorporate this definition, and should be made to read”...(i) Reportable Disturbance, or...”. With this revision, when BAL-002-1 is retired the definition of Reportable Disturbance can be retired as well. The SDT is looking into this possibility. Regarding the Rationale for Requirement R1, should Reportable Area Control Error be Reporting ACE? Reporting ACE is in the NERC Glossary, Reportable Area Control Error is not. The SDT agrees and has made the change.

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	In the second paragraph of the Rationale for Requirement R1 that reads"...as described in R1.3 below..." should be revised to read "as described in Part 1.3...". The SDT agrees and has made the change. Measure M1 should be revised to read "...that demonstrates compliance with Parts 1.2 and 1.3.". The SDT agrees and has made the change. In Requirement R2, and Measure M2 "Firm" should not be capitalized. "Firm Load" is not in the NERC Glossary. It should be revised to read firm Load. The SDT has modified the requirement and therefore made modified the measure accordingly. Additional comments: 1) The proposed standard continues with several "compliance traps" which will hamper operators' effective use of Contingency Reserves to mitigate reliability problems, and then could cause compliance exposure due to auditor interpretation. For example, R1 would require a BA to deploy at least some of its reserves in order to declare an EEA exemption even if there may not be an immediate need to do so. The SDT has modified the language and believes that your concern has bewen addressed. 2) There are contradictory portions of the standard which would leave operators confused and again lead to compliance exposure. a. For example, Part 1.3 (ii) does not include an exemption for deploying Contingency Reserve for a Contingency that is not a NERC defined Balancing Contingency Event. R2 does have an exemption for this and other scenarios. The term "sudden" being included in the definition of a Balancing Contingency Event is

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	the source of the problem. See the second scenario of Attachment A (sent by E-mail to Darrel Richardson). The SDT has removed the language referenced and modified Requirement R2 to have a process for Contingency Reserve in their Operating Plan b. R1 does not treat subsequent Contingencies in a consistent manner, again related to the term "sudden" being included in the definition of a Balancing Contingency Event. See the first scenario in Attachment A (sent by E-mail to Darrel Richardson). The term "sudden" is used in the definition of a wide category. This category may be used to refine the needed recovery for a Reportable Balancing Contingency Event under R1 in the proposed standard. The drafting team believes that as structured, the term "sudden" does not need further definition as any definitive definition would be somewhat arbitrary and possibly ill-fitting for one size entity while perfectly reasonable for another. While the example you provide works very well for the single entity that it covers, this type of structure is not likely to work for a nation-wide standard. The standard covers entities such as relatively small Balancing Authorities like LADWP to very large entities such as PJM. Therefore a stated MW amount, or even a stated percentage would not treat all entities evenly or fairly. The drafting team supports the concept that each entity could provide further definition through written procedures to clarify how that entity implements their program. The drafting team disagrees with the need to add a sentence to the definition of Reportable BCE. The starting time of an event is determined by the definition of Pre-Reporting Contingency Event ACE Value. 3) There are several problems with the definitions including definitions of Most Severe Single Contingency (MSSC), Contingency Event Recovery Period (CERP), and Balancing Contingency Event (BCE).

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	a. MSSC does not include concurrently dropped load which may cause a Balancing Authority to carry extra Contingency Reserve beyond its actual MSSC. If load is dropped concurrently, the size of the event is the size of the generator, the load that drops is reserve for that event and the response requires only an amount of additional reserve over and above the net amount. It should be pointed out that if this load does not drop for the loss of another unit, the actual amount of reserve needed may be more than the net amount, depending on the size of the next largest contingency. b. BCE is unclear with regard to both generation and transmission events. (Also consider if A. Item b within the BCE definition instead referred to an unplanned change in ACE as opposed to an unexpected change in ACE.) 4) Regarding R2: a. R2 is far more complex than necessary, is unclear, and contains potential for gaming. b. Much less complicated language is proposed here, based on the original NERC Policy 1. Suggest the revision of R2 to read: R2. The Responsible Entity, if deficient in Contingency Reserves, has 90 minutes to restore. If the Responsible Entity experiences a Reportable Balancing Contingency Event during this time an additional 15 minutes are allotted." An alternative suggested rewording of R2:R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering all other events that may reduce this amount. This, together with the recovery provision in R1 (results-based requirement) and the provision in Requirement R6 and Attachment 1 of EOP-011-1 (which defines EEA levels) would collectively take care of many of the conditions listed in the proposed Requirement R2 including active monitoring of the amount of reserve to meet the Contingency Reserve

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	requirement. R2 as presented in this draft requires a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 as shown preceding. We believe this together with the recovery provision in R1 would take care of many of the conditions listed in the proposed Requirement R2. c. The language in Part 2.2 regarding Operating Instruction appears to allow operating personnel to create exemptions from R2 at will. The SDT has removed the language referenced and modified Requirement R2 to have a process for Contingency Reserve in their Operating Plan d. Requirement R2 continues to not include a number of "grace hours" per quarter, as requested in some industry comments. It may have a net effect of increasing the amount of available contingency reserve to some BAs which may marginally increase reliability. However, this needs to be balanced against increased operating costs due to carrying more reserve. e. Requirement R2 may produce a perverse incentive. A BA may let its ACE remain negative to keep the reserve monitor numbers above MSSC. Also, without a number of "grace hours" per quarter, there may be a susceptibility to loads running unexpectedly high near the end of a Clock Hour, causing a miniscule shortfall that results in an occasional "nuisance" compliance violation. f. R2 also causes BAs to carry much higher Contingency Reserves than necessary during the latter portions of the hour in order to "make the numbers come out right" if they are below MSSC in the beginning of the hour. g. Requirement R2 creates an artificial increase in reserves in order to maintain an amount over-and-above that required by the standard to meet non-DCS operational events, thereby increasing costs to ratepayers for no increase in reliability.

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	h. R2 will encourage operators to not deploy reserves when needed for reliability in order to meet compliance with this requirement, which could be detrimental to reliability. i. Entities that have to shed firm customer load (because load cannot be shed fast enough) to maintain reserves to meet compliance with this requirement is not an action that should be taken for reliability. j. In our previous comments, we found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met requirement R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. k. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs thereby rendering a BA unable to meet requirement R1, then the following bulleted item may be added under Part 1.3 in R1: o When the Responsible Entity is using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the excedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL). 5) The last sentence of metric M2 which splits a Clock Hour into sub-periods is difficult to follow and seems to add unnecessary complexity in determining compliance. 6) When the exemption in Part 2.6 becomes relevant, it most likely will occur within the middle of a Clock Hour. It is not clear if "instantaneous values showing reserves" refers to the sum of Contingency Reserve available plus Firm Load that can be shed. 7) Part 1.3 and R2 should be cognizant of unexpected loss of reserve without it being accompanied by a loss of power being delivered. In the last posting, we expressed a concern with the term “sudden loss” (see below). We are unable to find any response in

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	the Summary Consideration report that addresses this comment. Please consider these comments and provide a response. A Balancing Contingency Event is vaguely defined as a “Sudden loss of generation...” or “sudden decline in ACE...”. The word “sudden” is imprecise, and should be clarified. We suggest that the standard be clearer about defining the start time for a Reportable BCE. We support definitions like that used in NPCC Directory 5 section 5.17 where it says that the start of an event has occurred when a specific X amount of MWs are lost in a specific Y amount of time. Therefore, we suggest that the drafting team add precision in determining minute T+0 for an event by adding the following sentence (or something like it) to the Reportable BCE definition: “Following the resource failure, the Reportable BCE starting time is defined as the first chronological rolling one minute interval that meets the reduction in resource output(s) criteria stated herein.” The SDT’s response to comment does not appear to address this particular comment. We ask the SDT to please provide the rationale as to why this suggestion was not adopted. The SDT has removed the language referenced and modified Requirement R2 to have a process for Contingency Reserve in their Operating Plan To summarize, the January 2015 version of BAL-002-2 could be improved by providing better clarity within the definitions and making simplifications that yield a more "operator-friendly" standard. There is a concern that the complexity and nuances of the proposed standard in some circumstances could be a distraction to the operator when more important reliability tasks need to be performed. The standard is complex because the issues we are addressing are many and interrelated. A simple standard would be: R1, Correct your ACE within 15 minutes of the loss of a resource R2. Replace any Contingency Reserve within 105 minutes of the loss of a resource R3. If no resource is lost, Contingency Reserve must equal an entity’s MSSC for each data point base on the entity’s SCADA scan rate.

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	This would not provide the necessary information to be able to consistently define compliance within the standard and to date has not been supported by the majority of the industry.
PPL NERC Registered Affiliates	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.The PPL NERC Registered Affiliates support the comments provided by PJM. In addition, we submit the following comments: It is not clear how the compliance exemptions in R1.2 and R2.6 for a Responsible Entity experiencing an EEA would apply to a RSG. Since an RSG cannot request the RC to declare an EEA , it appears the RSG would be required to maintain MSSC level reserves regardless of the EEA status of its member BAs. It also appears the RSG could be found non-compliant with both R1.2 and R2.6 simultaneousl. We suggest that while a member of a RSG is in an EEA, its MSSC and Contingency Reserve Requirement (the member BA's reserve obligation to the RSG) are removed from the RSG. The reconfigured RSG would continue to maintain the RSG based on the new MSSC and the revised assignment of CRR among the non-EEA members. The RSG would remain in this configuration for the duration of the member BA's EEA. The SDT does not completely agree with your comment. This assumption is possible for some RSGs but may not be possible for all RSGs. Assigning a Medium VRF to both R1 and R2 is not appropriate - the reliability impact of not having the required amount of reserves does not seem comparable to the reliability impact of not recovering ACE after a reportable BCE. The VRF for R2 should be lower than R1. If R2 cannot be revised as suggested by PJM, an alternative to the average Clock Hour measurement period should be provided. If reserves dip below the MSSC late in a Clock Hour, it is doubtful if a RE could act in time to resolve the shortfall. Also, what is the

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	reliability benefit of an RE acting to increase its reserves if the shortfall occurs earlier in the hour? It doesn't seem the average Clock Hour measurement period provides an RE much flexibility in complying with R2 nor does it improve BES reliability. A rolling hourly average or multi-Clock Hour average would be an improvement. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan. The SDT feels that neither of the requirements would definitely cause cascading outage but there is the possibility. For this reason the SDT believes that a medium VRF is correct. This also agrees with the current similar requirements VRFs. BAL-002-2 directly applies only to BAs and Reserve Sharing Groups, but it states in the definition of Contingency Reserve that the capacity mandated, "may be provided by resources such as Demand-Side Management (DSM), Interruptible Load and unloaded generation." That is, BAs can fulfill their BAL-002-2 obligations only by imposing demands on these other parties, and we would like to know up-front what they will be. This standard does not allow BAs to impose demands upon other parties. It allows a BA to provide the reserves from essentially any resource that meets the definition and intent of the response needed for compliance. This concern is heightened by the addition (effective 4/1/2015) of the expression, "and discourage response withdrawal through secondary control systems," to the NERC Glossary definition of Frequency Bias Setting. This change echoes the statement, "appropriate outer-loop controls (distributed controls) settings to avoid primary frequency response withdrawal," in the NERC Resource Subcommittee's 2013 Eastern Interconnection Frequency Initiative Whitepaper," and "Related outer-loop controls within the DCS, as well as applicable generating unit or plant controls, should be set to avoid early withdrawal of primary frequency response," in NERC's 2/5/2015 Industry Advisory, Generator Governor Frequency Response." Implementation of appropriate governor time delays and droop settings constitutes a well-defined and technologically justified form of GO involvement in frequency response improvement, but the term "response withdrawal" is vague and could cause BAL-002-2 to be misconstrued as

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	authorizing BAs to demand new, frequency response-enhancing services from GOs as a regulatory requirement rather than obtaining them through market mechanisms. The SDT believes that there is some confusion here. For clarity, Contingency Reserve response has nothing to do with the issue raised in your comment. Contingency Reserve response is measured over a 10-15 minute period, not the time periods discussed in the referenced document.
MISO	We commend the drafting team on the effort committed to this project and appreciate the improvements. We also appreciate the various objectives the team is trying to meet, but believe it is time to step back and ensure we are moving in a direction where NERC is trying to go with clearer, results-based standards. We understand that the team is trying to meet their interpretation of Order No. 693 directives. We respectfully submit that much of what the FERC directed may be moot as the directives related to primary, secondary, and tertiary control, have been met by other standards projects. This is particularly true considering the equally effective R2 (Balancing Authority ACE Limit, BAAL) in BAL-001-2 and a performance based Frequency Response Standard. The current BAL-002 is well understood by system operators and performance as posted on the NERC “Adequate Level of Reliability (ALR) Metrics” website has been stellar. The draft out for comment is not easily understood, adds complexity, and will likely increase customer cost for no discernable reliability value. The drafting team will only point to the existing interpretation and NOPR proposed by FERC to remand the interpretation and state that while MISO may operate based on their understanding of tradition and history, there is obviously a clear disconnect between the regulatory interpretation of the current standard and the industry’s interpretation of the existing standard. IF the regulated and regulators cannot agree on what the standard says, then it obviously needs corrected. The drafting team believes that taking a standard from 6 requirements to 2 requirements while essentially continuing to operate as history would show has been done is not a significant change.

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	If the standard effort reaches an impasse, it may be time to hold a technical conference to get resolution on a few key items: 1] What should be the obligation of the Balancing Authority for events > MSSC? [We suggest that such events are reported to demonstrate best efforts were made, but compliance is not assessed. The BA is still accountable for BAAL. Finally there are backstop standards as load shedding is mandated in the EOP and IRO standards for harmful frequency conditions and IROL exceedances] The drafting team agrees with this position. We also believe that this is what the existing standard says. Clearly our regulators do not. Both industry and our regulators agree that this proposed standard does say that. 2] What constitutes a continent-wide contingency reserve policy? [We believe the policy could be met by developing simple definitions for the various categories of operating reserves as any can be used to meet DCS or the other Balancing Standards in real time. The policy should state that the BA performs an analysis to develop warning and alarm points for their operators for the reserves needed to meet BAL-001, BAL-002, and BAL-003. Having BAs provide this data to in real time to their Reliability Coordinators would add reliability value to the EEA and other EOP processes. Finally, a guidelines document on reserves approved by the NERC Operating Committee could be part of this policy] 3] Since there are now performance based BAAL and FRS in place, could we not actually simplify the current DCS? [Retain a cleaner version of the current R1, and a simpler R2 that requires presenting reserve values to BA and RC with appropriate alarm points] 4] The extent the remaining 693 directives have been met by other standards projects. [We believe BAAL addresses the Commission's concerns for detecting and responding to significant high or low frequency events, addresses the concern about performance to individual events, and is a performance-based double-confirmation of secondary and tertiary reserves] 5]For those requirements that are ultimately proposed, is there a way to keep them simple and easy to understand as opposed to being overly precise [For example, if there

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	are exclusions in a requirement, rather than trying to calculate reserve recovery to the minute, exclude the hour when the situation occurs and the following hour(s), the number of hours determined by the extent contingency reserves were depleted)? The SDT is not sure we understand how you are suggesting we simplify the proposed standard. The SDT has made significant modifications to the requirements which hopefully has addressed your concerns. We agree with comments submitted by the IRC-SRC and MRO-NSRF as applied to the current draft. The question is whether to continue to adjust the current draft or make sure we are creating a solution that is relatively simple to apply and provides reliability value. If we continue down the current path for the standard, we have two primary concerns. Our first concern is that the lowering of the threshold to 900 MW in the East, coupled with the proposed change from quarterly average performance to individual event performance, will increase customer costs for no discernable reduction in reliability risk. Both DCS performance (ALR statistics) and frequency performance (NERC Resources Subcommittee minutes) show frequency performance is more than adequate. As noted by Chairwoman LaFleur at NERC Board meetings, we should consider the reliability benefits of a standard vs. its costs. Costs will increase with the lower threshold for our customers. Because the interconnection is over-biased (ACE overstates resource loss) and dispatchers operate conservatively, our operators will likely deploy set-aside contingency reserves for any loss over 750 MW rather than wait to double-check the event size. (An event is defined by the size of the resource lost, not the change in ACE.) This will likely add scores of contingency reserve deployment cases each year for situations that could likely be met by other on-line reserves. The proposed standard does not require the activation of a specific reserve product, it requires correcting ACE within the specified time period. There is no requirement for any entity to respond in a specific manner.

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	Finally, it should be noted that the frequency change from a 900 MW loss in the East is barely beyond the change from a Time Error Correction. Our recommendation is that the standard uses the lesser of 80% of MSSC or 1000 MW for the East. The SDT does not see the significance in changing from a 900 MW to 1000 MW reporting threshold. The SDT does not believe that the lower threshold will place any undue burden on the reporting of events. The SDT would welcome any information that you could provide to justify the suggested modification. We also recommend that NERC retains the quarterly reporting. Individual cases of non-compliance can be tallied in the form to achieve the FERC directive, but we believe it is important that Enforcement assesses compliance base on the aggregate performance of the BA or RSG, not just spot observations. Our second major concern with the current posting for comment is that R2 goes beyond the original intent of the DCS. The reason there are no measures for this requirement in BAL-002-0 is that it was never intended to be a commodity standard. The predecessor to DCS was Policy 1, which had guidelines on operating reserves. The first DCS was one of NERC's first performance-based standards and existed prior to the ERO. The intent was to retain the concept of the guide to plan to have a certain amount of reserves. The measures of success were to meet CPS and DCS. DCS' intent was to respond quickly to all large events, with performance evaluated on events 80%-100% of MSSC. The intent of the 90 minute reserve replenishment was to get ready for future events (meaning you'd be held for compliance to the standard for events 90 minutes thereafter). Another reason for our concern is that this commodity requirement is being proposed without any data to support what actually is carried hour to hour across the Interconnections and the extent operators draw on these reserves to keep their system balanced. If R2 is retained as proposed, we believe that it should be a "positioning" requirement, not a zero-defect requirement. As proposed, either customer costs will increase or reliability will be negatively impacted. The only way to have more than 100% reserves all the time in normal operations is to carry well more than 100% reserves as a basis of operations or choose not to deploy reserves for non-reportable events and draw

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	on frequency bias to keep reserves available. While the proposal provides some exclusions, the requirement should start on the basis that there will always be some variability and unforeseen non-consequential events that will require reserve deployment. If retained, we suggest R2 should require contingency reserves > 100% MSSC for 99% of all applicable hours. It should be noted that just because a BA has less than MSSC in one hour in four days, does not mean that it had zero reserves in that hour. Additionally, in a multi-BA Interconnection, the odds that the Interconnection would be deficient in Reserves with a 99% BA standard are astronomical. In a single-BA Interconnection there are backstops in the EOP and IRO standards. BAL standards are for normal operations. Other standards protect against events > N-1. Finally, we believe there should be a single quarterly report for R1 and R2. The R1 portion should be simplified to be very similar to today, to include reporting of events > MSSC (but not part of compliance evaluation). The quarterly R2 portion of the report should have the number of non-excluded hours the BA had reserves < MSSC and an identifier which hours were excludable under 2.1 through 2.6. Individual event reporting versus quarterly reporting includes the following points: 1. The minimum requirement for compliance is 100 percent so any failure to respond causes a non-compliance. The question then is how is a fine determined? Should it be based on the percentage of events for which compliance was/was not obtained, the percentage of failed response (i.e. total response needed for all events was 1,000, response received was 950) 2. Quarterly reporting averages can move based on the number of reportable events in a quarter, the size of reportable events or other variable that arguable have no bearing on the impact to the BES of an entity’s failure to meet the response requirement. Depending on the answer to the first issue, this may or may not be a reasonable metric. Just because it has been used for compliance purposes, that does not mean it is a reasonable measure of reliability or impact to reliability.

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	If we assume that the total response provided in the quarter divided by the total response required in the quarter, only the MWs failed to be delivered matters, not the amount of time afterwards. Therefore, an individual event evaluation provides for a much better means to determine the impact to reliability from a single failure as opposed to a quarterly mishmash of all events. The drafting team believes that while a quarterly report may provide good data for trend analysis, it is a poor means to determine compliance. The individual event reporting moves the compliance process to meet the already used enforcement process. This also satisfies a FERC Order 693 directive. From Order 693 354. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters.
MRO-NERC Standards Review Forum	We commend the drafting team on the improvements made since the last posting. Below are our concerns and recommendations for improvement. The NSRF is concerned that the lowering of the threshold to 900 MW for the Reportable Balancing Contingency Event in the Eastern Interconnection, coupled with the proposed change from quarterly average performance to individual event performance will increase customer costs and significantly increase compliance exposure for no difference in reliability risk. Because the interconnection is over-biased (ACE overstates resource loss) and operators operate conservatively, they will likely deploy contingency reserves for any loss over 800 MW. Our recommendation is that the standard uses the lesser of 80% of MSSC or 1000 MW for the Eastern Interconnection. The SDT does not see the significance in changing from a 900 MW to 1000 MW reporting threshold. The SDT does not believe that the lower threshold will place any undue burden

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	on the reporting of events. The SDT would welcome any information that you could provide to justify the suggested modification. Don't Change from Present Quarterly Reporting: We have fundamental concerns with changing the current quarterly reporting to exception reporting. We can find no directive for this change which increases compliance exposure and will have unintended consequences in how Reserve Sharing Groups (RSG) will operate. A failure of a contingency resource to start or start a minute late can cause performance that has a very low score for that single event, even though recovery is only a minute late or two late. There are RSGs that mitigate this compliance risk by deploying reserves for much smaller events, which helps reliability by quickly recovering from smaller events and replenishing these reserves as well as giving operators repeated practice in reserve deployment. Since each and every event is individually sanctionable, these RSGs will quickly change their rules to raise their reportable threshold to the interconnection minimum. Exception reporting will also eliminate a data source that is used for NERC's RAPA group and the State of Reliability Report: http://www.nerc.com/pa/RAPA/ri/Pages/DCSEvents.aspx, which is another step backward. We believe there should be a single quarterly report for R1 and R2. The R1 portion would be very similar to today, to include reporting of events > MSSC (but not part of compliance evaluation). The quarterly R2 portion of the report should have the number of hours the BA had reserves < MSSC and an identifier which hours were excludable under 2.1 through 2.6. . The VSLs should be based on the number of hours that reserves were < MSSC and not excluded: o Low: 2 or fewer hours (represents 0.09% of the hours in the quarter) o Medium: 3-5 hours o High: 6-9 hours o Severe: 10 or more hours (10 hours represents 0.5% of the hours in a month) NERC is trying to move away from zero defect standards. This standard should be structured to support that concept.

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	The reporting approach need not hard coded in requirements, but could be compliance section of the standard. Individual event reporting versus quarterly reporting includes the following points: 1. The minimum requirement for compliance is 100 percent so any failure to respond causes a non-compliance. The question then is how is a fine determined? Should it be based on the percentage of events for which compliance was/was not obtained, the percentage of failed response (i.e. total response needed for all events was 1,000, response received was 950) 2. Quarterly reporting averages can move based on the number of reportable events in a quarter, the size of reportable events or other variable that arguable have no bearing on the impact to the BES of an entity's failure to meet the response requirement. Depending on the answer to the first issue, this may or may not be a reasonable metric. Just because it has been used for compliance purposes, that does not mean it is a reasonable measure of reliability or impact to reliability. If we assume that the total response provided in the quarter divided by the total response required in the quarter, only the MWs failed to be delivered matters, not the amount of time afterwards. Therefore, an individual event evaluation provides for a much better means to determine the impact to reliability from a single failure as opposed to a quarterly mishmash of all events. The drafting team believes that while a quarterly report may provide good data for trend analysis, it is a poor means to determine compliance. The individual event reporting moves the compliance process to meet the already used enforcement process. This also satisfies a FERC Order 693 directive. From Order 693 354. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's

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	position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters We also had comments on a few specific items in R1. Our suggested wording changes are in [ ]. ***1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated [or depleted]. ***Contingencies can happen that take away reserves without the reserves being activated. And if these contingencies aren't "sudden", then it appears there is no acknowledgment of the reserve loss under the standard. ***(ii) after multiple Balancing Contingency Events for which the combined [capacity] magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. ***Contingencies of partially loaded generators remove not only MW from the BA, but the reserves they had as headroom. It is possible to have multiple contingencies where the MW loss is < MSSC, but reserves that were lost completely deplete the BA of its contingency reserves. There should be clarification that the magnitude loss is based on capacity, not MW loss. The SDT has made significant modifications to Requirement R1.

END OF REPORT