Consideration of Comments

Project 2009-03 Emergency Operations

The Project 2009-03 Emergency Operations Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from July 2, 2014 through August 15, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 56 sets of comments, including comments from approximately 174 different people from approximately 120 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, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

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

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

.

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	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.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

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

10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc,	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Ben Wu	Orange and Rockland Utilities Inc,	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	John A. Libertz	The FRCC Operating Committee (Member Services)	X									
N/A												
3. Group	Janet Smith	Arizona Public Service Company	X		X		X	X				
N/A												
4. Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
N/A												
5. Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6

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

8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
6.	Group	Richard Hoag	FirstEnergy Corp	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FirstEnergy Corp	RFC	1
2.	Cindy Stewart	FirstEnergy Corp	RFC	3
3.	Doug Houlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstENergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6

				1	2	3	4	5	6	7	8	9	10
7.	Group	Jared Shakespeare	Peak Reliability	X									

N/A

				1	2	3	4	5	6	7	8	9	10
8.	Group	Connie Lowe	Dominion	X				X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		SERC	1, 3, 5, 6
2.	Mike Garton		NPCC	5
3.	Randi Heise		RFC	5, 6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Kaleb Brimhall	Colorado Springs Utilities	WECC	1, 5, 6
3.	Michelle Corley	Cleco Power	SPP	1, 3, 5, 6
4.	Louis Guidry	Cleco Power	SPP	1, 3, 5, 6
5.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
6.	Robert Hirchak	Cleco Power	SPP	1, 3, 5, 6

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

7.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
8.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
9.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
10.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
11.	Jeff Knottek	City Utilities of Springfield	SPP	1, 4
12.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
13.	Ron Losh	Southwest Power Pool	SPP	2
14.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
15.	Shannon Mickens	Southwest Power Pool	SPP	2
16.	James Nail	City of Independence, MO	SPP	3, 5
17.	Randy Root	Grand River Dam Authority	SPP	1
18.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
19.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6
20.	Sing Tay	Oklahoma Gas & Electric	SPP	1, 3, 5
21.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
22.	J. Scott Williams	City Utilities of Springfield	SPP	1, 4
23.	Bryn Wilson	Oklahoma Gas & Electric	SPP	1, 3, 5

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

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniak	Generation Optimization	RFC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. 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

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
2. Brenda Truhe	PPL Electric Utilities Corporation	RFC	1									
3. Annette Bannon	PPL Generation, LLC	RFC	5									
4.	PPL Susquehanna, LLC	RFC	5									
5.	PPL Montana, LLC	WECC	5									
6. Elizabeth Davis	PPL EnergyPlus	MRO										
7.		NPCC										
8.		RFC										
9.		SERC										
10.		SPP										
11.		WECC										
13. Group	Tom McElhinney	JEA	X		X		X					
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Ted Hobson		FRCC	1									
2. Garry Baker		FRCC	3									
3. John Babik		FRCC	5									
14. Group	Stuart Goza	SERC OC Review Group	X		X		X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Joel Wise	TVA	SERC	1, 3, 5, 6									
2. Connie Lowe	Dominion	SERC	1, 3, 6									
3. Ray Phillips	AMEA	SERC	4									
4. William Berry	OMU	SERC	3									
15. 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									
16. Group	Carol Chinn	Florida Municipal Power Agency	X			X	X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									

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

1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utilities Authority	FRCC	4
6.	Randy Hahn	Ocala Uitlity Services	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	4
8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	City of Green Cove Springs	FRCC	3
10.	Tom Reedy	Florida Municipal Power Pool	FRCC	6
11.	Steve Lancaster	Beaches Energy Services	FRCC	3
12.	Richard Bachmeier	Gainesville Regional Utilities	FRCC	1
13.	Mike Blough	Kissimmee Utility Authority	FRCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Michael Lowman	Duke Energy	X		X		X	X				

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	Wayne Johnson	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				
N/A												
19. Group	Erica Esche	Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	X		X		X	X				
N/A												
20. Group	Ben Engelby	ACES Standards Collaborators						X				

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
2.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
3.	Matthew Caves	Western Farmers Electric Cooperative	SPP	1, 5
4.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Luis Zargoza	Sunflower Electric Power Corporation	SPP	1
6.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
7.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
8.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
9.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
10.	Steve McElhaney	South Mississippi Electric Power Association	SERC	1, 3, 4, 6
11.	Karl Kohlrus	Prairie Power Inc.	SERC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21. Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
22. Group	Greg Campoli	ISO/RTO Cojuncil Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Al DiCaprio	PJM	RFC	2
2.	Cheryl Moseley	ERCOT	ERCOT	2
3.	Kathleen Goodman	ISO-NE	NPCC	2
4.	Ali Miremadi	CAISO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Terry Bilke	MISO	MRO	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Ben Li	NPCC	NPCC 2										
23.	Group	Sandra Shaffer	PacifiCorp						X				
N/A													
24.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Sanford	Transmission Dispatch	WECC	1
2.	Chris Higgins	Transmission Dispatch	WECC	1
3.	Fran Halpin	Duty Scheduling	WECC	5

25.	Individual	Wendy	NERC										
26.	Individual	Julius Horvath	Wind Energy Transmission Texas, LLC	X									
27.	Individual	Len Kula	Independent Electricity System Operator		X								
28.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
29.	Individual	Anthony Jablonski	ReliabilityFirst										X
30.	Individual	John Brockhan	CenterPoint Energy Houston Electric, LLC	X									
31.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
32.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
33.	Individual	Linda Campbell	FRCC										X
34.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
35.	Individual	Russell Noble	Public Utility District No. 1 of Cowlitz County, WA			X	X	X					
36.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X					
37.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
38.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
39.	Individual	Denise Lietz	Puget Sound Energy	X		X		X					
40.	Individual	Richard Vine	California ISO		X								
41.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
42.	Individual	Josh Smith	Oncor Electric Delivery LLC	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
43.	Individual	Dave Willis	Idaho Power Co.	X									
44.	Individual	Andrew Pusztai	American Transmission Company LLC	X									
45.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
46.	Individual	Karin Schweitzer	Texas Reliability Entity										X
47.	Individual	Rich Salgo	NV Energy	X		X		X					
48.	Individual	Chris Scanlon	Exelon Companies	X		X		X	X				
49.	Individual	Scott Langston	City of Tallahassee	X									
50.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
51.	Individual	Bob Thomas and Alice Schum	Illinois Municipal Electric Agency				X						
52.	Individual	Matthew Beilfuss	Wisconsin Electric			X	X	X					
53.	Individual	David Jendras	Ameren	X		X		X	X				
54.	Individual	Cheryl Moseley	Electric Reliability of Texas, Inc.		X								
55.	Individual	Marc Donaldson	Tacoma Power	X		X	X	X	X				
56.	Individual	Joshua Andersen	Salt River Project	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"
FirstEnergy Corp	Agree	FE supports PJM's comments
Tennessee Valley Authority	Agree	SERC OC Review Group
South Carolina Electric and Gas	Agree	SERC OC
Seminole Electric Cooperative, Inc.	Agree	FRCC Operating Committee
Kansas City Power & Light	Agree	SPP - Robert Rhodes
California ISO	Agree	ISO/RTO Standards Review Committee
Hydro-Quebec TransEnergie	Agree	NPCC
City of Tallahassee	Agree	The FRCC Operating Committee (Member Services)
South Carolina Electric and Gas	Agree	SERC OC
Illinois Municipal Electric Agency	Agree	PJM, and SERC OC Review Group
Colorado Springs Utilities		Southwest Power Pool (SPP)
Lincoln Electric System		SPP Standards Review Group

1. **Based on comments from stakeholders, the EOP SDT has added the term “Operator-Controlled” preceding the language “manual Load shedding” in Parts of Requirements R1 and R2. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: The Emergency Operations Standard Drafting Team (EOP SDT) appreciates the comments received by industry. Based on the feedback received, the EOP SDT modified Requirements R1.2.6 and R2.4.8. The SDT changed wording to better reflect the intent described in the rationale by stating that the manual Load shedding plan overlap with automatic plans should be minimized. Other comments received requested the SDT to remove the term “Emergency” from “Emergency Operating Plan,” the EOP SDT agrees and made that change. Finally, commenters requested that the EOP SDT modify Requirements R1 and R2 to include the terms “not applicable.” The EOP SDT modified Requirements R1 and R2 to include “not applicable” within the requirements, where the prior version reflected this intent by the SDT within the rationale box.

Organization	Yes or No	Question 1 Comment
DTE Electric	No	In 1.2.6 and 2.4.8, the "Operator-Controlled" language is acceptable but "coordinated to minimize the use of automatic Load sheding" is vague compared to the intent of the requirement as explained in the Rationale. Since the intent is to reduce the overlap between manual and automatic Load shedding schemes, why not state it clearly in the requirement? Consider changing 1.2.6 and 2.4.8 to "Operator-controlled manual Load shedding plan coordinated to minimize the overlap with automatic Load shedding schemes." EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised requirements.
Duke Energy	No	Duke Energy agrees in concept with R1 and R2, but feel that the language used in R1.2.6 and R2.4.8, should be revised to better reflect what we perceive to be the SDT’s intent. We suggest that the language should more closely mirror that which is stated in the accompanying guideline document. We suggest the following revision for R1.2.6, and R2.4.8:”Operator-controlled manual Load shedding plan coordinated to minimize the use of Load shed under automatic Load shedding;” EOP SDT: The SDT appreciates your comments and have modified the requirements that they believe reflects the changes you recommended.

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	(1) We do not agree with the approach of combining glossary terms with everyday language. The term "Operator-Controlled" should be a complete defined term "Operator-Controlled Manual Load Shedding." The approach to combine capitalized terms and lowercase terms only leads to confusion. (2) This is also the case with the combination of two separate defined terms "Emergency Operating Plan." It is confusing for the drafting team to combine two independent glossary terms ("Emergency" and "Operating Plan") and expect everyone to understand the meaning of the combined terms. We strongly recommend that the drafting reconsider its approach on introducing separate defined terms. It is unreasonable to expect consistent interpretations with this approach.(3) There is a similar issue with the use of Capacity and Energy Emergencies. The defined terms are Capacity Emergency and Energy Emergency but by putting the "and" between the two, it looks Capacity is a defined term. (4) In regard to the "Emergency Operating Plan," does this apply to "Energy Emergencies" or "Capacity Emergencies," or just "Emergencies"? Wouldn't it be easier for the requirement to drop the word "Emergency" and require an "Operating Plan" instead? The definition of an Operating Plan includes an example of restoration activities, which is very close to what the drafting team is trying to convey. There is not a benefit for combining the terms, as a single term would suffice.(5) If an entity is registered as both a BA and a TOP, would they need two operating plans to address the differences in R1 and R2? If so, we recommend revising these requirements to eliminate duplicative efforts for compliance purposes. EOP SDT: The SDT was not defining a new term when it was capitalizing the term Operator at the beginning of a sentence. The SDT has removed the term "Emergency" from "Emergency Operating Plan" and has settled on "Operating Plan" throughout the document and added the define terms of "Capacity Emergency" and "Energy Emergency." The SDT understands that the an Operating Plan could be used for both the Balancing Authority and Transmission Operator, but the SDT separated out the requirements as they relate to the Balancing Authority and Transmission Operator. The requirements remain separate and applicable to each Entity.
PacifiCorp	No	PacifiCorp generally supports the added term "Operator-Controlled" preceding "manual Load shedding" in parts of Requirements R1 and R2. Added clarity for R1 and R2 would be provided by including portions of the Rationale section in the Requirement. Therefore, PacifiCorp recommends the Standard Drafting Team include a stand alone subrequirement in R1 and R2 pertaining to Load shedding, which reads as follows: "For Load shedding plans, automatic Load

Organization	Yes or No	Question 1 Comment
		shedding schemes are an important backstop against cascading outages or system collapse. If an entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. The Emergency Operating Plan shall include Operator-Controlled manual Load shedding plan(s) coordinated to minimize the use of automatic Load shedding.” EOP SDT: The SDT appreciates your comments and have modified the requirements that they believe add the necessary clarity that your comment recommends.
American Electric Power	No	AEP has no objection to the qualifier “Operator-controlled”, however each unique situation would dictate whether the appropriate action to take would be manual or automatic. R1 should allow such flexibility in the strategies specified. EOP SDT: The SDT appreciates your comments and have modified the requirements that they believe still allows for the flexibility needed during times when an Operator needs to take action.
NV Energy	No	The continued inclusion of the concept of coordination (or separation) of the Operator-Controlled manual Load shedding with the automatic underfrequency Load shedding is inappropriate for reliability, and the vague and ambiguous language raises auditability concerns. Underfrequency load shedding schemes are carefully coordinated across the Region to ensure that prescribed percentage steps of an area’s load are shed at specific system frequency levels. The subrequirements R1.2.6 and R2.4.8 both convey that an entity should strive to minimize any overlap between its manual load shedding circuits and those that will be shed automatically by underfrequency. This approach results in an undesirable skewing of the percentage of an entity’s load that will be shed by its underfrequency program. Specifically, the shedding of an entity’s load manually, if the load is completely separate from the underfrequency circuits, will increase the percentage of remaining load that is to be shed by the entity’s underfrequency program, jeopardizing the desired balance of the Regional underfrequency program coordination.The sub-requirements R1.2.6 and R2.4.8 are written with vague language. Taking the parent Requirements R1 and R2 into account, the entity is to develop maintain, and implement a Plan, which at a minimum, shall include: Strategies to prepare for and mitigate Emergencies including: Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding. As written, it is unclear what evidence would demonstrate adequacy with satisfaction of these requirements. The Rationale statements for R1 and R2 speak to the Entity evaluating their automatic load shedding schemes and coordinating so that overlapping use of Loads is avoided to the extent

Organization	Yes or No	Question 1 Comment
		reasonably possible, but there is no clarity as to what threshold an auditor would accept for the resultant overlap. Particularly, given the consequence of over-shedding automatic underfrequency loads if one were to fully segregate manual load shed circuits from automatic load shed circuits as explained above, it does not appear that these two sub-requirements promote BES reliability. We recommend removal of both sub-requirements R1.2.6 and R2.4.8, and addressing these matters in relevant NERC guidance documents. EOP SDT: The SDT appreciates your comments, but believe that it is important to retain the requirements, as modified, based on industry comments.
Wisconsin Electric	No	The term “Operator-controlled” with respect to load shedding is not adequately defined. Control could be interpreted to be via EMS/SCADA functionality or by dispatch of personnel executing switching. EOP SDT: The SDT appreciates your comments and have reflected your concerns in the requirement and rationale.
Northeast Power Coordinating Council	Yes	For consistency with the Rationale listed for R2 pertaining to “If any Parts of Requirement R2 are not applicable”, a similar statement should be listed under the Rationale for R1. Suggest adding the wording: “If any Parts of Requirement R1, Part 1.2 are not applicable, the Transmission Operator should note 'not applicable’ in their plan.” EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised requirements.
The FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	We think that “Operator-Controlled” is redundant as “manual load shedding” requires that it is initiated and operated by someone. We do not object, but think it unnecessary. EOP SDT: The SDT appreciates your comments but, after discussion of the comments, the SDT has retained the words “Operator-controlled.”
MRO NERC Standards Review Forum	Yes	
Peak Reliability	Yes	
Dominion	Yes	For consistency with the Rationale listed for R2 pertaining to “any Parts of Requirement R2 are not applicable”, a similar statement should be listed under the rationale for R1. Dominion

Organization	Yes or No	Question 1 Comment
		suggests adding; If any Parts of Requirement R1, Part 1.2 are not applicable, the Transmission Operator should note “not applicable’ in their plan. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised requirements.
SPP Standards Review Group	Yes	However, as written Requirement R1, Part 1.2.6 requires that the manual Load shedding plan minimize the use of automatic Load shedding. We believe the intent of the drafting team is for the requirement to state that the manual Load shedding plan should minimize the shedding of Load contained in the automatic Load shedding program. Otherwise the requirement reads that automatic Load shedding is a part of the manual Load shedding plan. We suggest the following language change for clarification: ‘Operator-controlled manual Load shedding plan coordinated to minimize the amount of load designated in both the manual Load shedding and automatic Load shedding programs;’. This same comment would also apply to Requirement 2, Part 2.4.8. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised requirements.
SERC OC Review Group	Yes	For consistency with the Rationale listed for R2 pertaining to “any Parts of Requirement R2 are not applicable”, a similar statement should be listed under the rationale for R1. The SERC OC Review Group suggests adding; If any Parts of Requirement R1, Part 1.2 are not applicable, the Transmission Operator should note “not applicable’ in their plan. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised requirements.
Florida Municipal Power Agency	Yes	FMPA supports the comments submitted by FRCC.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern	Yes	

Organization	Yes or No	Question 1 Comment
Company Generation and Energy Marketing		
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
ISO/RTO Cojuncil Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Wind Energy Transmission Texas, LLC	Yes	
Independent Electricity System Operator	Yes	
CenterPoint Energy Houston Electric, LLC	Yes	
Xcel Energy	Yes	
Public Utility District No. 1 of Cowlitz County, WA	Yes	However, PUD No. 1 of Cowlitz County, WA (District) finds the following sentence in the Rationale for R1 to be awkward: "It is the EOP SDT's intent for Requirement R1 Part 1.2.6 that what is unwanted is the use manual Load shedding which is already armed for automatic Load shedding." The District also finds the following phrase in the Rationale for R2 "...is to minimize as much as possible the use manual Load shedding..." is missing the word "of" between "use" and "manual," or might be improved with the words "the use" being replaced with "using." The District suggests using similar construct for both rationales, with a preference with the verbiage used for Requirement R2. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised rational statements.
Manitoba Hydro	Yes	

Organization	Yes or No	Question 1 Comment
Lincoln Electric System	Yes	
MidAmerican Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	Yes	The addition of Operator-Controlled does not seem to change the intent of the requirement. The extent of operator control may be just limited to activating the load shedding application in EMS. I don't agree or disagree with the change. EOP SDT: The SDT appreciates your comments.
American Transmission Company LLC	Yes	
Texas Reliability Entity	Yes	
Ameren	Yes	
Tacoma Power	Yes	
Salt River Project	Yes	
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.

2. **Based on comments from a majority of stakeholders, the EOP SDT removed Requirement 3 from EOP-011-1 draft 1 and has placed the requirement on the Balancing Authority and Transmission Operator to coordinate their Emergency Operating Plans with impacted Balancing Authorities and Transmission Operators. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: The EOP SDT appreciates the comments received from the industry. Based on the feedback received, the EOP SDT deleted Requirements R1.3 and R2.5. The EOP SDT then redrafted Requirement R3 to have the Reliability Coordinator review and determine reliability risks that exist between Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. In making these revisions, the EOP SDT has made it the responsibility of the Reliability Coordinator to look for potential reliability risks between multiple plans. The EOP SDT has created a new Requirement R4; whereas, that if problems are identified by the Reliability Coordinator, the impacted Balancing Authorities or Transmission Operators must correct their plans within a timeframe specified by the Reliability Coordinator and resubmit the plans.

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	AZPS supported the inclusion of Requirement 3 in the standard. The role of the Reliability Coordinator is one of oversight and coordination. They have the wide-area viewpoint necessary to assess emergency operations plans in aggregate and see the interdependencies of the plans. AZPS recognizes that this updated proposal still has the RC included in an approver role but contends that the coordination piece is of equal importance. The standard now simply requires RC approval. There is no implication in the language that the RC should be reviewing all plans in aggregate looking for the regional impact of the combined plans. AZPS suggests that the RC is appropriate entity to both coordinate and approve the plans. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Duke Energy	No	We suggest revising R1.1.3 and R2.5 as follows:”Strategies for coordinating the Emergency Operating Plans of Balancing Authorities and Transmission Operators identified in their Emergency Operating Plan(s).We believe that the use of term “impacted” is too broad in the context of this requirement.

Organization	Yes or No	Question 2 Comment
		EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
ACES Standards Collaborators	No	We question the rationale of removing Requirement R3. Coordinating emergency operations in an RC Area is ultimately responsibility of the RC. We do not understand the rationale of transferring the responsibility to the TOPs and BAs in an RC Area. Our concern with this approach is the potential scrutiny from an auditor that the registered entity did not coordinate with all “impacted” BAs and TOPs. The requirement is vague as currently written. It’s theoretically possible that a BA or TOP in each interconnection would need to coordinate with every other BA or TOP in the same interconnection for emergency operations. As written, auditors could scrutinize the list of coordinating BAs and TOPs and state that there was not enough coordination for emergency operations. Is this the intent of coordination from the drafting team? If so, then we disagree with the approach and request the drafting team clearly define the scope of coordination. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
American Electric Power	No	AEP disagrees with the change, and recommends that this requirement return to the approach proposed in the previous draft. AEP believes the Reliability Coordinator is in the best position to take the lead in coordinating its Balancing Authority and Transmission Operator plans. This form of coordination could involve the Reliability Coordinator reviewing the plans to ensure that the plans are compatible with the RC overarching plan (FERC Order No 693 Paragraph 548 hints at the Reliability Coordinator having an “overarching plan.”) and support reliability of the Bulk Electric System. FERC Order No 693, Paragraph 547 states in part “While balancing authorities and transmission operators are capable of developing, maintaining and implementing plans to mitigate operating emergencies for their specific areas of responsibility, unlike reliability coordinators, they do not have wide-area views.” We are in favor of the Reliability Coordinator hosting workshops as a platform to allow its local Balancing Authority and Transmission Operator to air the plans as another form of coordination (MISO presently hosts workshops to accomplish this coordination task for its members.). EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.

Organization	Yes or No	Question 2 Comment
CenterPoint Energy Houston Electric, LLC	No	Please see CenterPoint Energy response to Question 3. CenterPoint Energy believes the coordination of the Emergency Operating Plans of the TOPs and BAs within an RC area should be administered by the RC, similar to the approach taken by the FERC-approved EOP-010-1 GMD standard's R1.2. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Public Utility District No. 1 of Cowlitz County, WA	No	The District believes the SDT intent is to advance a results based requirement for each BA and TOP to make a good faith effort to coordinate the Emergency Operating Plans (Plans), both during development and their implementation. The District agrees with this; however, Requirement Parts 1.3 & 2.5 will not assure the Plans will be coordinated among mutually impacted BAs and TOPs. The requirement for strategies be included in each Plan and implemented for coordination appears to stop short of the above stated goal. It is also confusing: does this include coordination both in the Plan development and the actual implementation during an Energy Emergency? How should enforcement respond to an instance where one entity reaches out to another, but is unable to get a response or cooperation? The District suggests Parts 1.3 & 2.5 remain the same, but that the Reliability Coordinator be tasked as part of the approval process to affirm coordination has been achieved. Please refer to comments responding to question 3. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Puget Sound Energy	No	It is difficult to determine whether the language in parts 1.3 and 2.5 requires the coordination of the plans during the development phase, during the implementation phase or both. The previous R3 appears to have addressed coordination during the development phase, but the structure of the current language seems to be more suited for coordination during the implementation phase. If the second option is the case, the SDT should consider revising the language to something like "Strategies for coordinating the implementation of Emergency Operating Plans..." EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
MidAmerican Energy	No	R1.3 and R2.5 state that strategies are required to coordinate Emergency Operating Plans with impact TOPs and BAs. The NSRF questions this. Each TOP or BA can have strategies between impacted TOPs and BAs and the RC can still disapprove of their coordinated plans, per R3. The amount of effort between TOPs and BAs "prior" to

Organization	Yes or No	Question 2 Comment
		submission to the RC could be rather great. The impacted entities may have perfectly coordinated plans but the RC could still disapprove them. The NSRF understands that the BA's and TOP's plans need to support the RC's plans. This will assure a steady state system during emergencies. R1 and R2 already prescribe that each TOP and BA have RC approved Emergency Operating Plans. Thus, we recommend that R1.3 and R2.5 be deleted. The RC has totoal control over their RC area and are best suited to approve all Emergency Operating Plans within their area of responsibility.R1.2.6 speaks of "coordination" between the TOP's manual Load shedding plans and the use of automatic Load shedding. This is clearly stated in the Rational box for R1.2.6 but the Requirement reads differently. Recommend R1.2.6 to read: "Operator-controlled manual Load shedding plan coordinated to minimize the over lapping with the use of automatic Load shedding; . Or read similar to the recommendation of R2.4.8. Another possible solution would be the following wording of "Operator-controlled manual and automatic load shedding programs have sufficient separation of loads between the programs to perform each of their respective intended plan functions". R2.4.8 reads similar to R1.2.6. But the Rational boxes are different, recommend that both Rationals read the same with the addition of "The reference is not intended to require coordination with other entities" be added to R1 Rational box. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4. As it relates to your comments about Load shedding, please see the Summary of Comments for Question 1.
Texas Reliability Entity	No	As currently written, Requirements R1 and R2 do not explicitly state that the BA and TOP shall coordinate their EOPs with impacted BAs and TOPs. R1.3 and R2.5 state that the TOP and BA, respectively, shall have EOPs that include "Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities." The requirement to have a strategy is not the same as requiring the TOP and BA to coordinate with impacted BAs and TOPs. As such, the requirement to coordinate from the removed Requirement R3 is no longer covered in the standard. Therefore the failure to coordinate is not enforceable and the reliability benefit is lost. Texas Reliability Entity, Inc. (Texas RE) recommends the EOP SDT consider adding a requirement as follows: "Each Balancing Authority and Transmission Operator shall coordinate their Emergency Operating Plans with the other Balancing Authorities and

Organization	Yes or No	Question 2 Comment
		Transmission Operators in their Reliability Coordinator Area to assure that the plans are compatible and support reliability in the Reliability Coordinator Area." Adding a requirement to coordinate would also require an addition to the VSL. Texas RE suggests the SDT add a Severe only VSL for failure to coordinate with all BAs and TOPs in their RC Area. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement 3 and newly written Requirement 4.
Ameren	No	We believe that the RC should take responsibility for the coordination, at least at the transmission level. Below the transmission level it could be the BA and TOP. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Northeast Power Coordinating Council	Yes	We agree that Emergency Operating Plans should be coordinated. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
The FRCC Operating Committee (Member Services)	Yes	
Colorado Springs Utilities	Yes	
MRO NERC Standards Review Forum	Yes	R1.3 and R2.5 state that strategies are required to coordinate Emergency Operating Plans with impact TOPs and BAs. The NSRF questions this. Each TOP or BA can have strategies between impacted TOPs and BAs and the RC can still disapprove of their coordinated plans, per R3. The amount of effort between TOPs and BAs "prior" to submission to the RC could be rather great. The impacted entities may have perfectly coordinated plans but the RC could still disapprove them. The NSRF understands that the BA's and TOP's plans need to support the RC's plans. This will assure a steady state system during emergencies. R1 and R2 already prescribe that each TOP and BA have RC approved Emergency Operating Plans. Thus, we recommend that R1.3 and R2.5 be deleted. The RC has totoal control over their RC area and are best suited to approve all Emergency Operating Plans within their area of responsibility.R1.2.6 speaks of "coordination" between the TOP's manual Load shedding plans and the use of automatic Load shedding. This is clearly stated in the Rational box for R1.2.6 but the Requirement reads differently. Recommend R1.2.6 to read: "Operator-controlled manual Load shedding plan coordinated to minimize the over lapping with the use of automatic Load shedding; . Or read similar to the recommendation of R2.4.8. Another

Organization	Yes or No	Question 2 Comment
		possible solution would be the following wording of "Operator-controlled manual and automatic load shedding programs have sufficient separation of loads between the programs to perform each of their respective intended plan functions". R2.4.8 reads similar to R1.2.6. But the Rational boxes are different, recommend that both Rationals read the same with the addition of "The reference is not intended to require coordination with other entities" be added to R1 Rational box. EOP SDT: EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4. As it relates to your comments about Load shedding, please see the Summary of Comments for Question 1.
Peak Reliability	Yes	
Dominion	Yes	We agree that Emergency Operating Plans should be coordinated. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
SPP Standards Review Group	Yes	
DTE Electric	Yes	
JEA	Yes	
SERC OC Review Group	Yes	The SERC OC Review Group agrees that Emergency Operating Plans should be coordinated. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Florida Municipal Power Agency	Yes	FMPA supports the comments submitted by FRCC.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	

Organization	Yes or No	Question 2 Comment
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	FOR EOP-011-1 R1 PART 1.3 AND R2 PART 2.5: REPLACE: “with impacted Balancing Autorities and Transmission Operators” WITH: “with Balancing Authorities and Transmission Operators known to be impacted by those plans.” RATIONALE: Compliance concerns with the current wording will likely drive email blasts to neighboring TOPs and BAs, and possibly all within the same Interconnection, thereby creating a volume of insignificant notifications such that notifications containing significant impacts are more likely be overlooked and BES reliability diminished. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
ISO/RTO Cojuncil Standards Review Committee	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Wind Energy Transmission Texas, LLC	Yes	
Independent Electricity System Operator	Yes	
ReliabilityFirst	Yes	
Xcel Energy	Yes	
Manitoba Hydro	Yes	
Lincoln Electric System	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	Yes	I was unable to find the requirement for coordinating Emergency Operating Plans with impacted Balancing Authorities and Transmission Operators. Requirement 1.3 says " Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities" this seems a little vague.

Organization	Yes or No	Question 2 Comment
		EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
American Transmission Company LLC	Yes	
NV Energy	Yes	
Wisconsin Electric	Yes	
Tacoma Power	Yes	
Salt River Project	Yes	

3. **The EOP SDT received several comments regarding Reliability Coordinator approval of Balancing Authority and Transmission Operator Emergency Operating Plans. The FERC directive in Paragraph 548 or Order No. 693 mandates that the Reliability Coordinator be included as an applicable entity; while plan approval by the Reliability Coordinator was not a specific mandated intent, the EOP SDT believes that approval by the Reliability Coordinator reduces risk to reliability of the BES. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: The EOP SDT appreciates the comments received from the industry. Based on the feedback received, the EOP SDT deleted Requirement R1.3 and R2.5. The EOP SDT then redrafted Requirement R3 to have the Reliability Coordinator review and determine reliability risks that exist between Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. In making these revisions, the EOP SDT has made it the responsibility of the Reliability Coordinator to look for potential reliability risks between multiple plans. The EOP SDT has created a new Requirement R4; whereas, that if problems are identified by the Reliability Coordinator, the impacted Balancing Authorities or Transmission Operators must correct their plans within a time frame specified by the Reliability Coordinator and resubmit the plans.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	Yes	We are concerned with the RC obligation to simply approve the TOP/BA EOPs. It implies that approval could be checking compliance. The Requirement or the Technical Guidance should provide direction and meaning to the approval. If the SDT was to codify the requirement then we would like to suggest language consistent with EOP-006.

Organization	Yes or No	Question 3 Comment
		Suggest:R3. Each Reliability Coordinator shall review the Emergency Operating Plans (EOPs) of the Transmission Operators and Balancing Authority within its Reliability Coordinator Area. 3.1 The Reliability Coordinator shall determine whether the Transmission Operator's or Balancing Authority's EOP is coordinated and compatible with the Reliability Coordinator's EOP and other Transmission Operators' EOPs within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with reasons stated, the Transmission Operator's or Balancing Authority's submitted EOP within 30 calendar days following the receipt of the EOP from the Transmission Operator or Balancing Authority. As an alternative, a section in the Guidelines and Technical Basis could be written to provide guidance. The RC role in the TOP or BA process to develop an EOP can vary based on the quantity of Emergency Operating Plans being submitted. When an RC provides its approval of a submitted EOP the RC must review the submitted EOP to verify it is compatible and coordinated with the RC's overarching emergency operating plans developed for its Wide Area responsibility. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
The FRCC Operating Committee (Member Services)	No	We do not feel that the approach by the SDT is fully responsive to the FERC directive nor is it consistent with the desire expressed in the order. In addition there is lack of clarity on what criteria the RCs should use to approve or disapprove individual TOP and BA plans. The requirement as written appears to simply add administrative burden and compliance implications that add little to improving reliability. Adding an "auditing" purpose to RCs duplicates compliance monitoring oversight of TOP and BA entities inappropriately and should not be added to the responsibility of RCs. We do acknowledge that the RC role is important in coordinating response to Emergencies however, contrary to EOP-006 (restoration) where the RC has a central role in guiding System restoration, individual BA and TOP responses to emergencies within their area is a much different operating scenario and the RCs role are likely to be very different. If the SDT determines that it is essential to have the RC involved in the approval process, we request criteria be provided for consistency otherwise criteria could be created by individual RCs and inconsistently applied across interconnections. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.

Organization	Yes or No	Question 3 Comment
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	
MRO NERC Standards Review Forum	Yes	The NSRF believes that with the RC approving Emergency Operating Plans, that they are "coordinating (align) Emergency Operating Plans within their RC area. This approveal process will reduce the risk of instability during emergencies. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
FirstEnergy Corp		
Peak Reliability	Yes	
Dominion	Yes	We agree that the SDT met the FERC directive and we also cite the comments of many as providing justification requiring such approval. In some areas, generation scheduling, dispatch and outage approval is done by an entity registered solely as BA while in others it is done by an entity that may be registered as BA and TOP. In others it is done by an entity registered as BA, TOP and RC. In order for this standard to accommodate these variations, we support a requirement that, at a minimum, requires the RC insure the individual plans are coordinated such that they can be utilized in an aggregated manner when necessary to maintain relibiability within the RCs reliability area. We could make similar statements relative to manual load shedding. BAs typically do not have field personnel and therefore must rely upon manual load shed plan 'owned' by an entity with such personnel (typically DP). In this case, it is appropriate for the BA's load shed plan to consist of contacting that entity (or entities) and directing a specified amount of load be shed within a defined amount of time. It is also appropriate for the BA's load shed plan to consist of contacting its RC and requesting that a specified amount of load be shed within a defined amount of time. In this example, the RC would then have to contact one or more entities directing them to shed a specified amount of load be shed within a defined amount of time. In either case, the RC would have reviewed and approved the Emergency Operating Plan developed by each BA and TOP within its reliability area based upon insuring that these plans are coordinated as necessary. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
SPP Standards Review Group	Yes	

Organization	Yes or No	Question 3 Comment
Tennessee Valley Authority		
DTE Electric	Yes	
PPL NERC Registered Affiliates	Yes	Requirement R3 specifies the amount of time the RC has to approve a BA or TOP's EOP; however, it does not specify the amount of time a TO or BA has to revise and resubmit the EOP in the event that an RC does not approve the initial submission.â€ƒ EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
JEA	No	The plan should not be required to be approved by the RC. We do not have a problem coordinating with them and providing them a copy as current standards require. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
SERC OC Review Group	Yes	
Seattle City Light	No	Seattle believes that while approval of emergency oeprating plans by the Reliability Coordinator might add BES reliability, it adds more compliance burden than it does add BES reliability. In addition, requiring separate approvals for TOP and BA emergency operating plans may reduce reliability for those entities such as Seattle that are both TOP and BA, because emergency plans that presently integrate TOP and BA activities will need to be made separate purely for compliance purposes. This separation will add unnecessary complexity and duplication to emergency plans, and offers potential for confusion during an emergency situation as opposed to a single integrated plan. Seattle recommends 1) that the SDT follow paragraph 548 of Order 693 as worded, and delete the requirement for approval of emergency plans by the Reliability Coordinator and 2) revise R1 and R2 to allow a single integrated emergency plan for entities that are both TOP and BA (which is common in WECC and represents a substantial fraction of the BAs existing within NERC). EOP SDT: EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4. The SDT understands that the an Operating Plan could be used for both the Balancing Authority and Transmission Operator, but the SDT separated the requirements that relate to the Balancing Authority and Transmission Operator. The requirements remain separate and applicable to each entity. The plan could be used for an entity that is registered as both BA and TOP.

Organization	Yes or No	Question 3 Comment
Florida Municipal Power Agency	No	FMPA supports the comments submitted by FRCC.
Duke Energy	No	Duke Energy is unclear on the justification of requiring an RC to approve the Emergency Operating Plans of a BA or TOP. Is there specific technical justification for the approval, and if so, does it add to the reliability of the BES? We understand that in Order 693, FERC directed that the RC be included as an applicable entity. However, we do not believe that this “inclusion” should necessarily rise to the level of being the approver of a BA or TOP’s Emergency Operating Plan. We feel that it would be more appropriate for an RC to be “knowledgeable and aware of all Emergency Operating Plans submitted” by the BA(s) and TOP(s) in its RC area. If the SDT determines that it is essential to have the RC(s) approve Emergency Operating Plan(s) developed by a BA and TOP, then we suggest that criteria be established to provide a consistent, measurable approach throughout the industry. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
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	No	Southern understands the SDT’s attempt to address the FERC directive from Order No. 693 to include the reliability coordinator as a necessary entity. Our concern, however, is the operational expectations (and potential compliance implications) of the wording as it stands using the word “approve” and the lack of guidance on what basis approval would be given. Southern agrees with FERC, as acknowledged in its Order for EOP-006, that approval of these plans does not guarantee that they will adequately mitigate an Emergency for a BA/TOP but merely that the plans are compatible and support reliability. Reviewing the various definitions of “approve” indicates it means to “judge favorably or good”. Without indicating the context upon which to “judge goodness” one might infer that it includes opportunity for operational success. Due to the details unique to each BA and TOP, only those entities are in a position to judge goodness with regard to operational success. The RC is not in a position to judge such details. The RC role should be limited to reviewing against a specific set of criteria. The RC could participate, as FERC expects, by reviewing the plans and notifying the submitting BA/TOP of issues in their plan based on incompatibility with neighboring BA/TOP emergency operating plans, the potential to create risk to wide area reliability, and incompatibility with RC distributed emergency operating plans. “Approval” and any associated implications on potential success would be avoided.Suggested alternate wording for R3 might be:Each Reliability Coordinator shall review Emergency Operating Plans submitted by Transmission

Organization	Yes or No	Question 3 Comment
		Operators and Balancing Authorities in its RC Area on the basis of a plan element's incompatibility with and non-reciprocal inter-dependency on neighboring BA/TOP emergency operating plans, the potential to create additional risk to wide-area reliability, and incompatibility with RC distributed emergency operating plans and then, within 30 calendar days of submittal, notify the submitting Transmission Operators and Balancing Authorities of any incompatibilities and/or reliability risks identified in the submittal.In addition, the SDT should include a companion requirement for BAs/TOPs to address any incompatibilities and/or reliability risks identified by their RC within a defined time period after being notified of such incompatibilities / reliability risks and certainly prior to the effective date of the Emergency Operating Plans. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	
ACES Standards Collaborators	No	As stated above, the RC should be the responsible entity to coordinate emergency operations in its area. The drafting team needs to consider requiring the RC to coordinate emergency operations with the applicable TOPs and BAs in its RC Area. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI agrees that this requirement provides opportunity for reduced risk to reliability, but disagrees with the assertion that it necessarily reduces risk. EOP SDT: The SDT appreciates your comments.
ISO/RTO Cojuncil Standards Review Committee	No	We are concerned with the lack of detail in the R3 requirement for the RC to approve the EOPs of the TOPs and BA. R3 should include a requirement for the BA and TOP to submit their proposed EOPs to the RC. Also, the lack of detail and criteria for approval in R3 could lead to a misinterpretation that RC approval involves checking compliance. We would like to suggest the following alternative language, which is along the lines of what is currently contained in EOP-005-2 and EOP-006-2:R3. Each Transmission Operator and Balancing Authority shall submit its proposed Emergency Operating Plan and any subsequent proposed changes to its Emergency Operating Plan to its Reliability Coordinator.3.1 The Reliability Coordinator shall review each proposed Emergency Operating Plan it receives

Organization	Yes or No	Question 3 Comment
		from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area and determine whether the Emergency Operating Plan is coordinated and compatible with the Reliability Coordinator's Emergency Operating Plan and shall approve or disapprove, with stated reasons for disapproval, the Emergency Operating Plan within 30 calendar days following the receipt of the Emergency Operating Plan from the Transmission Operator or Balancing Authority.Alternative, 3.1 can be stated as a separate requirement to avoid the confusion of having multiple entities in one requirements having different mandates.Note that ERCOT does not support this comment. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
NERC		
Wind Energy Transmission Texas, LLC	No	The proposed EOP change only further places unnecessary burden on the RC. We cannot understand why the RC should need to approve a company specific emergency plan. We have no issues with coordinating our EOP with the RC and neighboring TOPs, but we do not agree with requiring RC approval of company specific EOPs. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Independent Electricity System Operator	Yes	
American Electric Power	No	AEP does not support the Reliability Coordinator formally approving the Balancing Authority and Transmission Operator Emergency Plans. In FERC Order No. 693, Paragraph 632 (EOP-006-1), FERC clearly requires the Reliability Coordinator to be involved in the development and approval of restoration plans. FERC did not make this distinction of the Reliability Coordinator approving the EOP (EOP-001-0) plans. We believe EOP-011-1 R3 violates the intent of Paragraph 81 criteria B1. AEP supports the Reliability Coordinator role as a coordinator of the Operator plans as noted in our response to question #2. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
ReliabilityFirst	No	1. Requirement R1 and R2a. The following comment was supplied during the previous comment period and ReliabilityFirst believes it was not addressed.

Organization	Yes or No	Question 3 Comment
		ReliabilityFirst requests the following comment be responded to: ReliabilityFirst believes the “implement a Reliability Coordinator-approved Emergency Operating Plan” language is troublesome in a scenario where a Reliability Coordinator disapproves the Emergency Operating Plan (per Requirement R4). In this scenario, the Transmission Operator/Balancing Authority could be compliant with developing and maintaining the plan but without Reliability Coordinator approval of the plan, the Transmission Operator/Balancing Authority could potentially be deemed non-compliant with Requirement R1 and R2. ReliabilityFirst believes the “implement a Reliability Coordinator-approved Emergency Operating Plan” language should be taken out of Requirements R1 and R2 respectively. ReliabilityFirst recommends including a new Requirement R5 which states “Upon Reliability Coordinator approval of the Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans, the Transmission Operator and Balancing Authority shall implement the approved Emergency Operating Plan.” EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
CenterPoint Energy Houston Electric, LLC	No	Since FERC did not mandate RC approval in Paragraph 548, CenterPoint Energy does not believe that using RC approval is the most sensible method to satisfy FERC’s directive. Instead, CenterPoint Energy recommends that EOP-011-1 adopts an approach similar to the FERC-approved EOP-010-1 GMD standard. Thus, for R1: “Each RC shall develop, maintain, and implement an Emergency Operating Plan that coordinates Emergency Operating Procedures or Emergency Operating Processes within its RC Area. The Emergency Operating Plan shall include a process for the RC to review and to coordinate the Emergency Operating Procedures or Emergency Operating Processes of the TOPs and BAs within its RC Area.” For R2: “Each TOP shall develop, maintain, and implement Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission system. At a minimum, the Operating Procedures or Operating Processes shall include the following elements:...”. For R3: “Each BA shall develop, maintain, and implement Emergency Operating Procedures or Emergency Operating Processes to mitigate Capacity and Energy Emergencies. At a minimum, the Operating Procedures or Operating Processes shall include the following elements:...”.

Organization	Yes or No	Question 3 Comment
		EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
South Carolina Electric and Gas		
Seminole Electric Cooperative, Inc.		
FRCC		
Xcel Energy	Yes	
Public Utility District No. 1 of Cowlitz County, WA	No	The District agrees with the concept, but finds there are no defined elements the RC should follow before issuing approval or disapproval of an Emergency Operating Plan (Plan). Please see comment to question 2. The SDT's intent appears not to encompass a goal of assuring each plan is compliant before approval. Rather, the intent appears merely to establish an opportunity to reduce risk to the BES. While the District does not believe the RC should be placed in the compliance auditor's role, there is concern that the approval process will greatly vary depending upon the particular RC, or the amount of time available to review Plans. While a 30-day allowance to review a single Plan for approval or disapproval may be reasonable, the SDT should consider instances where the RC will need to review many Plans together as an interweaving coordinated effort for a large operational footprint. Further, the SDT should consider establishing minimum Plan review objectives before Plan approval is granted. Otherwise, the RC will be allowed to rubberstamp Plans with little or no serious review. The District proposes the following be considered: 1) require the RC to review each submitted Plan and document findings. 2) Approval or disapproval of a Plan is based on the findings from the review. 3) Allow the RC to issue conditional approval subject to further review when additional time is required to analyze coordination with other impacted TOPs and BAs. 4) Require the RC to retain an up-to-date archive of all Plans within its footprint to assist its review for coordination between plans and application for lessons learned. 5) Require the RC to recall an approved Plan when it discovers a weakness or gap, and give notice to the affected entity why the Plan has been recalled. 6) Require entities that have been given notice of a recalled Plan to submit a revised Plan for approval. 7) Consider whether or not the RC should be given expressed final authority to resolve coordination issues between plans. EOP SDT: EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written

Organization	Yes or No	Question 3 Comment
		Requirement R4. The other provided comments that require additional RC oversight may help define process, the EOP SDT believes they tend to be administrative in nature and should not be addressed in this standard.
Manitoba Hydro	Yes	
Kansas City Power & Light		
Lincoln Electric System	Yes	
Puget Sound Energy	No	Imposition of an RC approval process for these plans will impose a significant burden on the RCs, as well as on the BAs and TOPs. It would be better to model the required coordination after the approach implemented in IRO-010 - where the RC specifies additional requirements for the plans and the BAs and TOPs are required to comply with those specifications. This approach will allow an RC to address specific interconnection and RC area issues, but does not impose the significant administrative burden of coordination with each BA and TOP within its area. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
California ISO		
MidAmerican Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	No	The new R3 says that the RC will approve or disapprove the submitted plans. If they are charged with approving a plan it seems there should be some requirement to ensure that they are coordinated. With the elemination of the old R3 the approval seems incomplete.The Reliability Coordinator must be able to access all BA and TOP Emergency Procedures and have the ability to ensure that procedures are coordinated and do not conflict with each other. However to require the Reliability Coordinator to Approve all Emergency Operating plans will increase the burden on all entites involved with little increase in system reliability.IPC System Planning like that the change assumes some level of coordination between the RC and TOPs. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
American Transmission Company LLC	Yes	
Hydro-Quebec TransEnergie		

Organization	Yes or No	Question 3 Comment
Texas Reliability Entity	No	RC approval of the TOP EOPs places an unnecessary burden on both entities, particularly in cases where plan updates may be administrative in nature. Also, by approving the TOP EOPs, the RC may be accepting an unnecessary legal risk by accepting a plan as sufficient and adequate to ensure reliability when they do not necessarily have detailed knowledge of the systems for which the EOPs were developed. The RC review, if any, should only ensure that the emergency plans are coordinated and compatible with the overall RC EOP and other entity plans in the RC area. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
NV Energy	Yes	We agree that the inclusion of the RC is achieved through the proposed provision of approval of the emergency plans. The Standard, however, is noticeably silent on the protocols that would be expected in the event that the RC is unable to approve one or more Plans, either the Transmission of Energy Emergency Plans. For instance, if the RC reviews a Plan but finds fault in it, how will compliance with the 30-day approval time limit be achieved? Further, what is the status of compliance of the Entity whose submitted Plan is returned for revision? There would be a period of time wherein the Entity may be operating under its Plan without attaining approval from the RC. Is the Entity in jeopardy of non-compliance by operating under an unapproved Plan? The VSLs don't address this possibility. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4. While a submitted plan may require additional changes as identified by the RC, this does not invalidate already-reviewed plans and would not place the Entity in a compliance risk.
Exelon Companies		
City of Tallahassee		
South Carolina Electric and Gas		
Illinois Municipal Electric Agency		
Wisconsin Electric	No	The standard as written does not sufficiently identify the criteria by which the RC would evaluate BA / TOP Emergency Operating Plans. The standard should include criteria similar to EOP-006, R5.1, potential language: The Reliability Coordinator shall determine whether the Emergency Operating Plan is coordinated and compatible with other Emergency Operating Plans within its Reliability Coordinator Area. The Reliability

Organization	Yes or No	Question 3 Comment
		Coordinator shall approve or disapprove, with stated reasons, the submitted emergency plan within 30 calendar days following the receipt of the plan from the BA/TOP. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Ameren	No	We believe that because the majority of manual load shedding is likely to be at sub-transmission voltage levels the RC will not have awareness of this load shedding and will need to rely on the TOP or BA for the specific details. EOP SDT: The SDT appreciates your comments.
Electric Reliability of Texas, Inc.	No	See response C. under Q7 below.
Tacoma Power	Yes	
Salt River Project	No	We do not agree that the RC approval is necessary to enhance reliability. The additional administrative burden for all of the applicable entities, including the RC, does not provide a significant enhancement to reliability. This burden includes evidence of submittal of the Plan to the RC, RC review of each plan in its footprint and evidence of RC approval for each entity. This is a significant burden for each entity that doesn't provide an equitable reliability enhancement. The EOP SDT should consider changing the language in requirements R1, R2 & R3 to state that emergency plan coordination with the RC is required, just as it is among BA's and TO's. The language could include a requirement for the RC to review each plan for coordination and effectiveness. We believe that the revised coordination language will satisfy the FERC Order 693 and minimize the administrative evidence burden on the applicable entities. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.

4. The EOP SDT has removed Requirement R5 from EOP-011-1 draft 1, as it is redundant with currently-enforceable TOP-001-1a. Do you agree with this revision? If not, please explain in the comment area below

Summary Consideration: Comments received from industry were supportive of this change; EOP-011-1 retains the deletion of Requirement R5.

Organization	Yes or No	Question 4 Comment
CenterPoint Energy Houston Electric, LLC	No	CenterPoint Energy agrees with the SDT that EOP-011-1 draft 1's R5 is redundant with currently-enforceable TOP-001-1a and therefore should be removed. However, CenterPoint Energy disagrees with the SDT's subsequent decision to re-create the same redundant requirement as EOP-011-1 draft 2 R1.2.1. Therefore, draft 2's R1.2.1 should be deleted because of the SDT's stated redundancy. EOP SDT: The SDT appreciates your comments. The SDT believes it is still an important part of a BA or TOP Operating Plan to include processes on notifying and keeping the RC informed of the conditions.
Northeast Power Coordinating Council	Yes	
The FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	

Organization	Yes or No	Question 4 Comment
MRO NERC Standards Review Forum	Yes	
Peak Reliability	Yes	BA requirement is still in R2.2
Dominion	Yes	
SPP Standards Review Group	Yes	
DTE Electric	Yes	
JEA	Yes	
SERC OC Review Group	Yes	
Seattle City Light	Yes	
Florida Municipal Power Agency	Yes	FMPA supports the comments submitted by FRCC.
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company Generation; Southern Company	Yes	

Organization	Yes or No	Question 4 Comment
Generation and Energy Marketing		
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	
ACES Standards Collaborators	Yes	We agree that redundant requirements should be removed. We also believe that combined glossary terms that lead to confusion and administrative tasks without reliability benefits should be removed. EOP SDT: The SDT appreciates your support and have redrafted terms so they should not be combined.
Associated Electric Cooperative, Inc. - JRO00088	Yes	
ISO/RTO Cojuncil Standards Review Committee	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Wind Energy Transmission Texas, LLC	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 4 Comment
American Electric Power	Yes	AEP agrees, and appreciates the drafting team's willingness to accept our earlier recommendation that R5 be removed.
ReliabilityFirst	Yes	
Xcel Energy	Yes	
Public Utility District No. 1 of Cowlitz County, WA	Yes	
Manitoba Hydro	Yes	
Lincoln Electric System	Yes	
Puget Sound Energy	Yes	
MidAmerican Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	Yes	
American Transmission Company LLC	Yes	
Texas Reliability Entity	Yes	Texas RE agrees with this revision. The requirement for a TOP to notify its RC of actual or expected emergencies is still in the draft TOP-001-3, as R8. EOP SDT: The SDT appreciates your support.
NV Energy	Yes	

Organization	Yes or No	Question 4 Comment
Wisconsin Electric	Yes	
Ameren	Yes	
Tacoma Power	Yes	
Salt River Project	Yes	

5. The EOP SDT has revised Attachment 1, removing “Operating Reserves” from EEA 2 and adding “Operating Reserves” into EEA 3. Do you agree with this change? If not, please explain in the comment area below

Summary Consideration: The EOP SDT appreciates the comments from the industry and have made changes to Attachment 1 that reflects the general concern that the industry would be shedding Load in order to maintain reserves. The SDT deleted 3.2 in the Attachment. The SDT also modified the “Circumstances” of EEA3 to read, “The energy deficient BA is unable to meet minimum Contingency Reserve requirements.” The SDT also eliminated the words “Inability to meet Operating Reserve requirement or,” from the EEA 3 “Title.” In addition, the SDT modified the “Circumstances” for EEA 2 that show that an entity will be in this level when it has implemented its Operating Plan to mitigate Emergencies but is still able to maintain Contingency reserves.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	The proposed move of utilizing Operating Reserve (OR) from EEA 2 to EEA 3 does not present any problems. However, we are concerned with the added sentence that “In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.” The sentence needs to be clarified. Even though the statement doesn’t stipulate that load has to be shed,

Organization	Yes or No	Question 5 Comment
		having to shed load can be construed. We do not agree that the deficient BA needs to shed firm load to meet the Operating Reserve requirement. Operating Reserve is carried to guard against demand variations and contingencies resulting from a loss of generating resource or import, and system contingencies. A BA should only shed load if a contingency occurs necessitating load reduction to restore system operation within well-defined limits. You do not operate to shed firm load to avoid having to shed firm load.The conclusion that may be reached is that a BA is required to shed firm load prior to committing its remaining Operating Reserves. This can be clarified by rephrasing to: In this situation, the requesting BA must be able to have an amount of firm Load shed if necessary to supplement its remaining Operating Reserves in order to meet its Operating Reserve requirement." EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
Arizona Public Service Company	No	This appears to constitute a change in the emergency response ideology. Under the current standard, it is not necessary to shed load to restore reserves at an EEA 2, unless they are called upon. The new proposal states that an entity must have the ability to shed load to restore reserves. The SDT has provided no rationale for this change. AZPS requests clarification on the rationale for this change if in fact the standard now states that firm customer load should be shed to restore reserves.As a secondary issue the movement of operating reserves from EEA 2 to EEA 3 is that it reduces the clarity of the EEA levels. The attachment to EOP-002-3.1 provides a clear trigger for each EEA level. Level 1 is triggered by having all resources in use while still maintaining the ability to meet all operating requirements. Level 2 is triggered by becoming reserve deficient while still maintaining the ability to meet all of your firm commitments. Level 3 is triggered by losing the ability to meet all of your firm commitments thereby becoming ACE deficient. The proposed changes leave the Level 1 trigger intact. The previous Level 2 trigger becomes the trigger for Level 3. This leaves no definitive trigger for Level 2. AZPS believes this will cause confusion as TOPs

Organization	Yes or No	Question 5 Comment
		transition between the EEA levels. Therefore AZPS recommends that the Operating Reserves remain in EEA 2 as in EOP-002-3.1. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments. The SDT reworked the circumstances for EEA 2 and, therefore, believe there are still definitive triggers between levels.
SPP Standards Review Group	No	By making this change, the drafting team is requiring deficient Balancing Authorities which can not maintain their Operating Reserve obligations to 'be able to' shed firm Load in order to maintain its reserve obligations. We seek clarification from the drafting team on whether the deficient Balancing Authority is required to actively shed load in order to maintain its reserves or only needs to have the capability to shed load to maintain its reserves. The drafting team has proposed this significant change without providing sufficient justification for the change. The proposed BAL-002-2 is referenced as the driver for this specific change. However, by our reading of the last posted version of BAL-002-2, R2 the responsible entity is given an exemption from needing to maintain its reserves if it has experienced a Contingency or is in an EEA 2 or EEA 3. The proposed language in EOP-011-1 is in direct conflict with this language. The exemption holds equally well for EEA 2 and EEA 3. So why change? Why move the Operating Reserve clause to EEA 3? We strongly recommend that the drafting team put the Operating Reserve clause back under EEA 2 where it belongs. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
DTE Electric	No	SDT did not provide rationale associated with this change.
PPL NERC Registered Affiliates	No	Operating Reserve requirement OR Firm Load interruption is imminent or in progress." The circumstance description in section 3 states that the "Requesting BA is unable to meet Operating Reserve requirements AND foresees a need for possible interruption of Firm Load." We feel that the STD inadvertently used the word "or" in the heading for Attachment A, section 3. We recommend that the heading be

Organization	Yes or No	Question 5 Comment
		changed to the following in order to make it consistent with the circumstance description in section 3.”EEA 3 - Inability to meet Operating Reserve requirements and firm Load interruption is imminent or in progress.”Note that firm load is not a defined term and should not be capitalized. If those changes are made, we would agree with the Operating Reserves being moved from EEA 2 to EEA 3. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments
SERC OC Review Group	No	The SERC OC Review Group feels there is still lack of understanding around the use of Operating Reserves vs. Contingency Reserves and believe further work is needed to provide better clarity. Changing the current definition of EEAs by moving the term Operating Reserves may not solve the conflict with BAL standards and adds unneeded complexity to this standard.Operating Reserves include Contingency Reserves and clarity should be added in the use of these terms in the Attachment.For Section 3.2 of the Attachment, should the wording be ‘Operating Reserves are being used’ or ‘Operating Reserves can be used’? EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments
Duke Energy	No	(1) In the proposed Attachment 1, Duke Energy believes the criteria for calling an EEA1 should be covered under the BA’s Emergency Operating Plan and that additional steps should be taken during EEA1 to prevent the BA from moving into the EEA2, such as calling for conservative operations, curtailment of ALL non-firm use of capacity resources except that retained as Contingency Reserve, and contacting the RC and impacted BAs/TOPs identified under the plan. In addition, we believe that taking some of the actions from EEA2 and moving them to EEA3 will make things more confusing for a System Operator to make the determination of what EEA level the entity is in. The proposed Attachment 1 places some of the actions taken under the currently effective EEA2 and just moves them to the proposed EEA3, muddying the water on how close a BA may

Organization	Yes or No	Question 5 Comment
		actually be to firm load shedding. Duke Energy believes clear separation should be maintained between the step of utilizing Contingency Reserves to meet firm load requirements, and the step where firm load shedding is imminent or in progress. Our interpretation is that utilizing your Contingency Reserve to meet firm load requirements is part of EEA2 and the shedding of firm load is part of EEA3 respectively. For example, a Balancing Authority (BA) that is maintaining 1000 MW of Contingency Reserves, along with having other measures it's capable of implementing upon use of such reserves (Emergency purchases, public appeals, voluntary load reductions of firm Commercial and Industrial customers,..), may be able to stay within the boundaries of an EEA2 and still maintain balance under BAL-001 without moving to EEA3.(2) Under the proposed Attachment 1, we believe that the required Operating Reserves should be changed to reference required Contingency Reserve, and as implemented to serve firm load, there should not be a requirement to shed load in order to maintain Contingency Reserves. (3) Under the NERC Functional Model, the Load Serving Entity (LSE) is responsible for managing its resource portfolio for meeting the demand and energy requirements of its End-use Customers. The LSE is responsible for coordinating its current-day, next-day, and seasonal operations with its Host Balancing Authority. To the extent that the LSE projects that it will be deficient in meeting its load requirements, the LSE is the entity responsible for working with Purchasing-Selling Entities to procure sufficient resources to address any deficiency. Among other activities under energy emergencies, the LSE communicates requests for voluntary load curtailment to its customers. At a minimum, Duke Energy believes that EOP-011 should retain the capability for the LSE to request the RC to call an EEA. Though EOP-011 and Attachment 1 may not have to be prescriptive in the activities expected of LSEs during an energy emergency, we believe that the responsibility of LSEs to procure additional resources as needed to address real-time deficiencies needs to be clearly understood and not be inadvertently moved to the Host BA by the changes proposed. (4) Based on our comments above, we suggest the following EEA levels

Organization	Yes or No	Question 5 Comment
		for consideration:1. EEA1 - All available resources in use to serve firm load, firm transactions, and required reserves.2. EEA2 - Utilization of Contingency Reserves and emergency assistance.3. EEA3 - Firm Load interruption is imminent or in progress.Further explanation is provided in our response to Question 7. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your concerns over the shedding of Load to maintain Operating Reserves. The SDT had industry support on the removing of the LSE from the Attachment and, therefore, has not returned it to the Attachment.
ACES Standards Collaborators	No	We are not supportive of shedding load to preserve Operating Reserves for an EEA 3 as presently included in Attachment 1, Section 3.2 of the standard. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
Associated Electric Cooperative, Inc. - JRO00088	No	See SERC OC Review Group comment
ISO/RTO Cojuncil Standards Review Committee	No	We are concerned with the added sentence that “In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.” We do not agree that the deficient BA needs to shed firm load to meet the OR requirement. For so long as OR is still available, albeit depleted, a BA should be able to continue to utilize its OR to meet resource/demand/interchange balance. We do not support the idea of shedding firm load to avoid having to shed firm load when a resource contingency occurs or before the OR is fully utilized.Note that ERCOT does not support this comment. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.

Organization	Yes or No	Question 5 Comment
PacifiCorp	No	PacifiCorp disagrees with removing “Operating Reserves” from EEA 2 and adding it to EEA 3. For background, it is our understanding that when the Reliability Coordinator is communicating Energy Emergency Alerts (EEA) to Balancing Authorities, there is an orderly progression in resource deficiency for EEA 1, 2, and 3: Level 1 is characterized as all resources being in service, yet reserve requirements are continuing to be met; Level 2 is characterized by an erosion in the resource/load balance to the point that operating reserves are being impacted; and finally, Level 3 indicates that firm Load may no longer be able to be served. The Standard Drafting Team’s proposal to move the inability to meet “Operating Reserves” characterization of system conditions into EEA 3 affects the orderly progression for EEA 1, EEA 2, and EEA 3.Proposed EEA 2 would involve deploying all resources except for contingency reserves, which would include deployment of Operating Reserves in excess of contingency reserves. However, proposed EEA 3 (supposedly more severe) states that Operating Reserves are maintained instead of deployed. This reverses the level of severity.The purpose of Operating Reserves is to be deployed to serve expected or unexpected swings in Load. When those swings occur, PacifiCorp deploys the Operating Reserves, up to the full amount available if necessary. The language in Attachment 1, Section 3.2 states that instead of deploying Operating Reserves to serve Load, entities would shed Load to serve our Operating Reserves. We find this unacceptable. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
Independent Electricity System Operator	No	We are indifferent with the proposed move of utilizing Operating Reserve (OR) from EEA 2 to EEA 3. However, we wonder if the result will be a greater # of EEA3 events. Also we are concerned with the added sentence that “In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.” We do not agree that the deficient BA needs to shed firm load to meet the OR requirement since OR is carried to guard against demand variations and contingencies resulting in loss of generating resource or import. For so long as OR is still available, albeit depleted, a BA should be able to continue to utilize its OR

Organization	Yes or No	Question 5 Comment
		to meet resource/demand/interchange balance. A BA should only shed load if a contingency occurs or when the OR is fully utilized and there still remains a resource/demand/interchange imbalance. In short, we do not support the idea of shedding firm load to avoid having to shed firm load when a resource contingency occurs or before the OR is fully utilized, unless such post-contingency actions are not quick enough to prevent instability or cascading due to loss of resource/import contingencies. Therefore, we suggest revising the last sentence in Section 3.2 of Attachment 1 to: "In this situation, the requesting BA must be able to shed firm Load if it is unable to meet resource/demand/interchange balance after fully utilizing its Operating Reserve. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
CenterPoint Energy Houston Electric, LLC	No	CenterPoint Energy does not disagree with the change regarding "Operating Reserves". However, CenterPoint Energy suggests the following revisions be made to Attachment 1-EOP-011-1 (Energy Emergency Alerts): Under Section B, EEA Levels, the Introduction paragraph speaks to establishing four levels of EEAs. CenterPoint Energy suggests changing this language to establishing three (3) levels of EEAs since there are only three levels used and described under Section B. Additionally, under Section B, 3. EEA 3, CenterPoint Energy does not feel that language in 3.5 (Returning to pre-Emergency conditions) should be included in the description for EEA 3. CenterPoint Energy suggests removing 3.5 and Alert 0 - Termination from the description of EEA 3 and adding a Section C which would include language described in 3.5 (Returning to pre-Emergency conditions) as well as Alert 0 - Termination. Furthermore, CenterPoint Energy suggest changing Alert 0 - Termination to just Termination. EOP SDT: SDT appreciates your comments has modified the number of levels to three, as suggested. The SDT believes it is important to maintain 3.5 and the Alert 0 language and has retained it in the current draft.

Organization	Yes or No	Question 5 Comment
MidAmerican Energy	No	MidAmerican is not supportive of shedding load to preserve Operating Reserves for an EEA 3 event as presently included in Attachment 1, Section 3.2 of the standard. MidAmerican believes that other actions can and should be taken prior to declaring EEA3 and / or shedding load just to maintain operating reserves. The revisions to EEA3 could lead to an inappropriate number of EEA3 events being called and possibly inappropriate load shedding. Any changes that could lead to inappropriate load shedding must be carefully considered. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
NV Energy	No	Traditionally, we have seen the EEA-1, -2, and -3 as an orderly progression in deficiency. Level 1 was characterized as all resources being in service, yet reserve requirements continuing to be met; Level 2 is characterized by an erosion in the resource/load balance to the point that operating reserves were being impacted; and finally, Level 3 indicates that firm Load may no longer be able to be served. The movment of “Operating Reserves” into EEA-3 seems to remove the distinction between EEA-1 and EEA-2 and makes an EEA-3 a significant step change in system condition from that of the EEA-2. The rationale for this change may be appropriate, and the change may be necessary; however, we are unable to find an explanation of the need for the change or what it is intended to accomplish. Also, we are concerned with the premise that the entity should shed some of its load in an EEA3 in order to maintain reserves. This appears to be contrary to our collective reliability goal of preserving service. Shedding the load for the sole purpose of retaining adequate reserves will unnecessarily deter from our reliability charge. Rather than shedding load pre-contingency, reliability is best served by continuing to serve the load and implementing load shed immediately following the contingency. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.

Organization	Yes or No	Question 5 Comment
Ameren	No	We believe that operating reserves should stay in EEA 2 until the conflict with operating reserves in BAL-002 is resolved. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
Tacoma Power	No	Attachment 1, EEA's 2 and 3 have been revised with respect to use of Operating Reserves. The Operating Reserve criteria have been removed from EEA 2, under EEA 3 is the following new requirement:3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement. It is unclear how this situation may or may not be applied to entities whom are a member of a reserve sharing group. While I believe I understand the intent of this requirement, it may lead to confusion or potential application of this requirement where it should not be applicable. I feel that further revisions are necessary to address Reserve Sharing Groups. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
The FRCC Operating Committee (Member Services)	Yes	
Colorado Springs Utilities	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	Dominion agrees with the change, but for additional clarity with an EEA3 (EEA 3-Inability to meet Operating Reserve requirement or Firm Load interruption is

Organization	Yes or No	Question 5 Comment
		imminent or in progress.) where you are NOT meeting Operating Reserves, Dominion suggests rewriting 3.2 to read as; Operating Reserves; such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
Florida Municipal Power Agency	Yes	FMPA supports the comments submitted by FRCC.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 5 Comment
Wind Energy Transmission Texas, LLC	Yes	
Manitoba Hydro	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	Yes	It keeps with the existing EEA1, EEA2 & EEA3 instead of interjecting an EEA4 in to the standard.
Texas Reliability Entity	Yes	
Wisconsin Electric	Yes	
Salt River Project	Yes	
Public Utility District No. 1 of Cowlitz County, WA		The District defers to BA comments.

6. Do you agree with the VRFs and VSLs in EOP-011-1? If not, please indicate which Requirement(s) and specifically what you disagree with, and provide suggestions for improvement

Summary Consideration: The EOP SDT appreciates the comments received from the industry. Time Horizon: The language of Requirements R1 and R2 require plans to be developed, maintained, and implemented. The EOP SDT believes that the current Time Horizons are correct, but "Long-term Planning" should be added. With the modification of Requirement R3, timeframe of 30 days, "Long-term" was not added.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	The Time Horizon for R1, R2 and R3 is currently Operations Planning. This should be Long-Term Planning. The definition of the two horizons are; Long-term Planning - a planning horizon of one year or longer. And Operations Planning - operating and resource plans from day-ahead up to and including seasonal. The EOP is developed for a period greater than a season.The condition "did not do so as soon as practical" in the HIGH VSL for R4 cannot be determined with any certainty or supported evidence. R4 itself need to be revised to provide the measurability to support compliance assessment. Please see the comment under Q7 regarding R4. We suggest revising the Medium VSL for R5 to Lower since failure to notify others that the alert has ended does not result in any unreliable operations. EOP SDT: Thank you for your comment. Time Horizon: The language of Requirements R1 and R2 says the plans are to be developed, maintained, and implemented. The EOP SDT believes that the current Time Horizons are correct, but "Long-term Planning" should be added. With the modification of R3 with a time frame of 30 days, Long-term was not added. R4: The VSLs were revised to comport with the revised language of the new time frame specified in the requirement.

Organization	Yes or No	Question 6 Comment
		R5: The EOPSDT concurs and has made the suggested revision.
Colorado Springs Utilities	No	1) R1 VSLs - How come the RC is approving a EOP that does not contain the required information?2) R1 VSLs - High VSL 2nd condition. If we fail to have a plan then we definitely failed to include 1.1 and 1.3. Think there is a typo.3) R3 VSLs - The RC should be responsible for verifying that EOPs have all the necessary parts before approval. This needs to be included in the VSLs for the RC under R3. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the measure of the number of subparts and placed VSL measures on the plans; that it is reviewed, maintained and implemented.
SPP Standards Review Group	No	The 2nd part of the High VSL for Requirement R1 should read: 'The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include either Part 1.1 or Part 1.3.'Requirements R1 and R2 require the Transmission Operator and Balancing Authority to develop, maintain and implement an Emergency Operating Plan. The High VSLs for both R1 and R2 hold the responsible entity as non-compliant if the entity failed to maintain its Emergency Operating Plan yet nothing in the requirements or the supporting documentation provide any guidance on what needs to be done to satisfactorily 'maintain' the plan. The industry needs to know what is expected in order to demonstrate compliance with this requirement. Additionally, the use of the term'implement' in these requirements apparently has a different meaning than in other reliability standards. In other standards when a plan, process or procedure is to be implemented, it means that the plan, process or procedure is to be issued, be readily available for operator use, and for operators to be trained on the plan, process or procedure. In EOP-011-1, implement means the plan was activated due to an operating condition which requires initiation of the EOP. The drafting team needs to be consistent with other drafting teams such that confusion is minimized. We believe the drafting team can correct this inconsistency by adding two new requirements, one for the TOP and one for the BA, which requires the responsible entity to activate, or initiate, its plan when an Emergency condition

Organization	Yes or No	Question 6 Comment
		arises. For example, the drafting team is referred to EOP-005-2, R7 which requires the responsible entity to execute its restoration plan when a blackout occurs. In fact, EOP-005-2 is a good example of how to incorporate develop, maintain and implement into a reliability standard.The redline version of the 1st part of the Severe VSL for Requirement R2 is missing the following lead-in phrase: 'The Balancing Authority had a Reliability Coordinator-approved...'Change the 'Transmission Operator and Balancing Authority' language in the VSLs for Requirement R3 to 'Transmission Operator or Balancing Authority'. Also, the Reliability Coordinator is non-compliant in the Severe VSL for Requirement R3 if it fails to approve/disapprove a submitted Emergency Operating Plan within 60 days or if it fails to approve/disapprove the submitted plan at all. Why not combine the two parts into a single VSL which states: 'The Reliability Coordinator failed to approve or disapprove, with stated reasons for disapproval, a Transmission Operator or Balancing Authority submitted or revised Emergency Operating Plan within 60-calendar days.' Please add calendar to the 30, 40, 50, etc. and hyphenate. For example, 30-calendar days, 40-calendar days, 50-calendar days, etc.How does the drafting team propose to measure 'as soon as practical' in the High VSL for Requirement R4? Since no notification was made in the Severe VSL for Requirement R4, delete the redundant 'as soon as practical' phrase from the Severe VSL.Delete the 'has' in '...alert has ended.' at the end of the Moderate VSL for Requirement R5. The High VSL for Requirment R5 requires the Reliability Coordinator to conduct conference calls as necessary to communicate System conditions. This specific item has been pulled from Attachment 1 which is referenced in Requirement R5. It is not specifically listed in the requirement and is one of a mirade of items contained in Attachment 1. Why has the drafting team chosen this specific item to single out in the VSL and not include it in the requirement? The need for the emphasis is questioned especially in light of recent work in Project 2014-03 associated with IRO-014-3, R3 which is currently posted for industry comment and ballot. Requirement 5 will be redundant with IRO-014-3, R3 if it is approved. We suggest the drafting team rethink the need for this

Organization	Yes or No	Question 6 Comment
		emphasis and more closely coordinate with the TOP/IRO Revisions drafting team in Project 2014-03. EOP SDT: The SDT appreciates your comments. EOP SDT has chosen not to tell the industry “how” to maintain their plan; but as requested by the industry in past standards, entities should be allowed to determine how is best to maintain the plan. The EOP SDT used the same language found in the approved EOP-010, which speaks to “implement,” and their intent is that to implement means to use the plan during an Emergency. The SDT modified the Requirement R3 language to avoid the issues with using day timeframes in the VSL. The rewritten Requirement R4 eliminates the term “as soon as practical,” and the VSL reflects the new language. Requirement R5 was also modified based on your comments.
DTE Electric	No	The Severe VSL for R4 is semantically the same as the High VSL for R4. Suggest removing "as soon as practical" from the Severe VSL for R4. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the language “as soon as practical.”
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	No	The language in the proposed VSLs for R4 is unclear: High VSLThe Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority and did notify other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators, but did not do so as soon as practical.Severe VSLThe Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority and failed to notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators.We propose that the Severe VSL be revised to remove “as soon as practical”. This will clarify the difference between the High VSL and Severe VSL. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the language “as soon as practical.”

Organization	Yes or No	Question 6 Comment
ACES Standards Collaborators	No	The VSL for R4 is ambiguous. How is an auditor or enforcement staff going to measure "as soon as practical?" This is a subjective measure and needs to be revised. One suggestion for improvement would be "without further delay." EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the language "as soon as practical."
ISO/RTO Cojuncil Standards Review Committee	No	A. The condition "did not do so as soon as practical" in the HIGH VSL for R4 cannot be determined with any certainty or supported evidence. R4 itself need to be revised to provide the measurability to support compliance assessment. Please see our comment under Q7.B. We suggest lowering the VSL for R5 from Medium to Low since failure to notify others that the alert has ended does not result in any unreliable operations. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the language "as soon as practical." The SDT agrees with your comment on Requirement R5 and has lowered the VSL.
Wind Energy Transmission Texas, LLC	No	The VSLs specifically state "The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan" and we don't agree with requiring the RC to approve company specific EOPs, therefore we cannot support the VSLs as written either. EOP SDT: The SDT appreciates your comments. The SDT modified the Requirement so the Reliability Coordinator no longer needs to "approve" the plan.
Independent Electricity System Operator	No	1. The condition "did not do so as soon as practical" in the HIGH VSL for R4 cannot be determined with any certainty or supported evidence. R4 itself need to be revised to provide the measurability to support compliance assessment. Please see our comment under Q7.2. We suggest moving the Medium VSL for R5 to Lower since failure to notify others that the alert has ended does not result in any unreliable operations

Organization	Yes or No	Question 6 Comment
		EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the language "as soon as practical." The SDT agrees with your comment on R5 and has lowered the VSL.
ReliabilityFirst	No	1. VSL for Requirement R1 - The second "OR" under the High VSL should not include the words "failed" in the first sentence fragment. ReliabilityFirst recommends the following for consideration: "The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but..."2. VSL for Requirement R5 - The VSLs for R5 all reference items in attachment 1 and not the actual requirement. RF recommends there be one Severe VSL which states: "The Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert, as detailed in Attachment 1." EOP SDT: The SDT appreciates your comments. The SDT modified the VSL for Requirement R1. The SDT agrees with your comment on Requirement R5 and has modified the VSL.
CenterPoint Energy Houston Electric, LLC	No	For R1 and R2, all the listed violation scenarios are documentation issues, except for the 3rd scenario of the Severe VSL for these two requirements. CenterPoint Energy firmly believes there should be no High or Severe VSL for simply failing to document a process or procedure. High or Severe VSL's should only apply to egregious violations that had a tangible impact on the reliability of the BES. Thus, CenterPoint Energy recommends that R1 and R2's VSL's be revised to focus more on performance-based issues with the following language. Lower VSL: The Transmission Operator does not have documented Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission System; or the Transmission Operator has documented Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission System but failed to coordinate with its Reliability Coordinator Emergency Operating Plan; or the Transmission Operator had documented Emergency Operating Procedures or Emergency Operating Processes to mitigate

Organization	Yes or No	Question 6 Comment
		operating Emergencies on its Transmission System that were coordinated with its a Reliability Coordinator Emergency Operating but failed to include one or more of the sub-parts of R1 as applicable. Moderate VSL: The Transmission Operator had documented Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission System that were coordinated with its Reliability Coordinator Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to implement one of the applicable sub-parts of R1 for an operating Emergency. High VSL: ...but failed to implement two of the applicable sub-parts of R1 for an operating Emergency. Severe VSL: ...but failed to implement three or more of the applicable sub-parts of R1 for an operating Emergency. **Response: Thank you for your comment.** EOP SDT: The SDT appreciates your comments. The SDT modified the VSL for Requirements R1 and R2 and removed the third scenario, and also the parts about document processes. The VSL is now based on the TOP or BA having, maintaining, implementing and getting the plan reviewed.
Public Utility District No. 1 of Cowlitz County, WA	No	R1 contains a typo in the High VSL column: "The Transmission Operator [failed to have] had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include either Part 1.1 or Part 1.3." R3 has no provision other than untimely approval or disapproval. It appears in the instance the RC runs out of time to review, a simple stamp of approval on day 29 or 30 is sufficient for compliance. If the goal is to simply require the RC to issue approval or disapproval (without any quality control of the review), this then appears to extend a substantial amount of trust without verification. **Response: Thank you for your comment.** EOP SDT: The SDT appreciates your comments. The SDT modified the VSL for Requirement R1. The SDT agrees with your comment on Requirement R3 and has modified the VSL.

Organization	Yes or No	Question 6 Comment
Lincoln Electric System	No	The 2nd. part of the High VSL for Requirement R1 should read: "The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include either Part 1.1 or Part 1.3." Additionally, the 3rd part of the High VSLs for R1 and R2 indicate that an entity is non-compliant upon failure to maintain its Emergency Operating Plan. In consideration that R1 and R2 do not specify a maintenance cycle for the Emergency Operating Plan, how would this VSL be evaluated? As an example, an entity may decide to review their Plan on a two-year cycle but an auditor could view a maintenance cycle greater than once per calendar year as a failure to adequately maintain the Plan. To simplify the VSL, recommend removing the third part altogether. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL for Requirements R1 and R2 and failure to maintain is now a moderate violation, but does not believe it should be removed.
Texas Reliability Entity	No	1)R1 High VSL appears to contain a copy/paste mistake in the second “OR” statement which states the TOP FAILED to have an RC approved EOP but goes on to say “but failed to include either Part 1.1 or Part 1.3.” Is the intent to capture that the TOP did have an approved RC plan “but failed to include either Part 1.1 or Part 1.3” rather than the TOP did not have a plan? The Severe VSL for R1 (second “OR” statement) covers the TOP failure to have an RC approved plan. Texas RE requests clarification from the SDT. 2) Texas RE recommends that R2 VSLs for all levels should specifically include the sub-parts of 2.4.1. Although it could be reasonably interpreted that the sub-parts of 2.4.1 are included, not explicitly stating they are included could pose issues in the enforcement realm (i.e., they would be unenforceable.) As currently written, a Registered Entity could include generating resources in its EOP without including those four sub parts (2.4.1.1.-2.4.1.4) and still be compliant. Texas RE recommends the EOP SDT add the phrase “including sub-parts of 2.4.1” immediately after “Sub-Parts 2.4.1.-2.4.9” in all the VSL levels.

Organization	Yes or No	Question 6 Comment
Ameren	No	We believe that R1 should be Medium. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL for Requirement R1 but believes that the requirement has multiple severity levels, and those are reflected in the VSL.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
SERC OC Review Group	Yes	
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	

Organization	Yes or No	Question 6 Comment
Bonneville Power Administration	Yes	
Xcel Energy	Yes	
Manitoba Hydro	Yes	
MidAmerican Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	Yes	IPC Grid Operations Training does not believe administrative tasks should have a high VSL attached to it. **Response: Thank you for your comment.** EOP SDT: The SDT appreciates your comments. The SDT was unsure which of the tasks you were referencing as being administrative. The SDT did lower the maintenance of the plan to Moderate with this revision of the standard.
Wisconsin Electric	Yes	
Tacoma Power	Yes	
Salt River Project	Yes	

7. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here

Summary Consideration: The EOP SDT has reviewed the comments in Question 7. The Standard was modified so that Load is not shed to maintain reserves. The SDT removed the requirement to have the Operating Plans approved by the Reliability Coordinator, and now are reviewed by the Reliability Coordinator for identification of any reliability risk with notification back to the BAs and TOPs. The term "System" was removed from the notification process in Requirements R1 and R2. The SDT modified the requirement so that it now states: "Management of Transmission and generation outages," as suggested by commenters. Timing requirements were added to the requirement to remove "as soon as practical." The term "Strategies" was replaced with "Processes" in Requirements R1 and R2. The SDT retained in the Standard the terms "potential" and "imminent" in Attachment 1 and the new Requirement R6 and believes these terms are appropriate. The SDT retained the reduction of internal utility energy; and if not applicable within a region, can be stated as such, but may be used in other regions. The SDT has replaced the term "requesting BA" in Attachment 1 with "energy deficient BA." The SDT made changes to the Standard, replacing "initiated" to "declared" where it is warranted. Voltage control was removed from the requirements, as suggested by commenters. The term "Emergency Operating Plan" was modified to "Operating Plan to mitigate Emergencies."

Organization	Question 7 Comment
ACES Standards Collaborators	(1) For Requirement R1, we recommend removing "strategies to prepare for" from parts 1.2 and 1.3. The elements of the Operating Plan should be processes or procedures to respond to an Emergency. As written, the Operating Plan will need to have both a strategy and a mitigation activity for each of the elements. How does one have a strategy and a mitigation activity for notifying the RC? Wouldn't that element be a process step? Parts 1.2 and 1.3 of this requirement need to be modified.(2) For Requirement R2, we recommend removing "strategies to prepare for" from parts 2.2 and 2.3. The elements of the Operating Plan should be processes or procedures to respond to an Emergency. As written, the Operating Plan will need to have both a strategy and a mitigation activity for each of the elements. How does one have a strategy and a mitigation activity

Organization	Question 7 Comment
	for notifying the RC? Wouldn't that element be a process step? Parts 2.2 and 2.3 of this requirement need to be modified.(3) For Requirement R4, we see no difference between the terms "as soon as practicable" and "as soon as practical." We strongly recommend revising this requirement with a reasonable measure of compliance. Also, as stated above, the VSL needs to be reworked, as the subjective measure of not notifying a BA or TOP as soon as practical results in a High violation severity level. This phrase is not appropriate for a reliability standard because it is ambiguous.(4) The term of "Operator-controlled manual Load shedding" should be a defined term. The word "operator" is not a defined term, although it could be assumed to refer to System Operators. There needs to be additional clarification on the intent of the drafting team.(5) There are still incomplete items on this project. The guidelines and technical basis should be included prior to ballot, not "to be added here after balloting." Without guidelines and technical basis for the drafting team's decisions, we cannot completely evaluate the standard, and therefore believe that more work is needed to improve the current draft.(6) Thank you for the opportunity to comment. Response: The EOP SDT has implemented the changes requested by ACES in Items 1, 2, and 3. The SDT does not believe that the term "Operated-controlled manual Load shedding" should be a defined term, as stated in Item 4. For Item 5, the guidelines and technical basis section of the standard is where the rationales from the requirements will be contained once the standard is approved; but during development of the standard, this information is placed in rationale boxes following each requirement.
MidAmerican Energy	: R1.2.3, Transmission is capitalized and generation is not, not sure if this is a type-o or not.R2.4.6, Customer fuel switching. The NSRF questions why this should be in an Emergency Operating Plan, since the customer will most likely be under 2.4.7, Demand response. As a BA, there are contracts with customers and if they elect to not be a signatory to those contracts, they always have the right to drop utility power and go on their owned and operated generation during the time of no utility power. Plus customers that own their own generation are excluded from the NERC Standards if they meet Exclusion E2 of the new BES definition. Recommend R2.4.6 be deleted from the R2. In addition to the above justification, there is no clear definition of "customer". Could a customer be

Organization	Question 7 Comment
	a single house hold that has a back up generator legally tied to their main circuit panel? This is another reason why R2.4.6 should be deleted. Response: The EOP SDT has modified the standard and believes it has incorporated your changes listed above by the deletion of 2.4.6.
Peak Reliability	1. Requirement 2.3: It is unclear whether this Requirement is for the BA to define criteria or simply reference criteria in Attachment 1. If the former, it appears inconsistent with the role of the RC in declaring EEAs. If the latter, it's unclear why this is necessary because the criteria already exists.2. Requirement 3:a. The Standard Drafting Team stated "While plan approval by the Reliability Coordinator is not specifically required by the directive in Order No. 693, the EOP SDT believes that approval by the Reliability Coordinator reduces risk to reliability of the BES." Please provide further clarity on the approval role of the RC. Several of the sub-requirements listed for BA R2, 2.4 are of such detail that the RC could not validate and therefore it is unclear how the RC would approve. Validation of R2.4 would be a Compliance Enforcement Authority function rather than an RC function.b. It appears there should there be a time delay after RC approval for each TOP/BA plan to be implemented in order to allow time for operators to be familiar with entity plans similar to the EOP-006-2 R6.3. If a BA is also a TOP, is only one Emergency Operating Plan required which cover all the requirements for both? Please clarify.4. There should be an annual review like there is for EOP-005/EOP-006. If annual or other scheduled periodic review and submittal becomes required, need verbiage on mutually agreeable schedule (reference EOP-005-2 R3). Response: The EOP SDT has implemented the changes to Requirement 2.3 to make it clear and not to have more criteria developed. The RC approval was removed from the standard. The EOP SDT does not believe that there needs to be a periodic review on the Operating Plan and has not included this requirement in the standard.
Independent Electricity System Operator	1. Requirement R4 is not measurable since there is no clear yardstick for "as soon as practical". While a time period may be subject to different views, we nevertheless suggest the SDT consider revising it to "shall notify, as soon as practical but no later than 5 minutes after receiving the notification," to put a bound on the time frame to support compliance assessment. 2. The wholesale replacement of "Energy Deficient Entity" with "Requesting BA" results in some

Organization	Question 7 Comment
	inconsistency with Condition (1) in the General Responsibility A.1 of Attachment 1, which indicates that a RC may initiated an EEA on its own request. Clearly, a RC will likely issue an EEA when it identifies a BA(s) in its RC Area is anticipating or experiencing energy deficiency. Nonetheless, the use of "Requesting BA" only in the rest of Attachment 1 fails to address the cases where a BA is energy deficient but it does not request its RC to initiate an EEA; rather, it's the RC that initiates the EEA before being requested. We suggest the SDT to consider replacing "Requesting BA" with "Energy Deficient BA" or simply reinstate the phrase "Energy Deficient Entity". Response: The EOP SDT has made the appropriate changes to the standard based on your comments.
Electric Reliability of Texas, Inc.	A. Load shedding to restore OR ERCOT does not support the paragraph 3.2 in Attachment 1 as currently drafted. There may be potential value in executing firm load shedding during periods when a region's reserve levels have been compromised. However, the decision to take this operating action should rest solely with the system operator for the region based on its regional rules and real-time operational information. (SHOULD THIS BE THE BA, THE RC OR BOTH? - DO WE WANT TO COMMENT ON THE APPROPRIATE FUNCTIONAL ENTITY TO TAKE THIS ACTION?). Accordingly, ERCOT suggests that the relevant language be deleted from Attachment 1. Appropriate revisions are proposed below. Alternative Proposed Language - delete the relevant language altogether and leave it to the regions to decide whether and how to utilize firm load shedding in the maintenance of system reliability. 3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. It is likely that different regions will have different approaches to potential firm load shedding during emergency operations. Accordingly, the most effective way to address the issue in Attachment 1, paragraph 3.2, is to delete the language, thereby effectively allowing regions to manage the use of firm load shedding during emergency operations based on their regional rules, as reflected in their EOPs. B. Requirements based on "potential" or "imminent" operating conditions R5 and Attachment 1 EEA 3 section impose obligations based on "potential" and "imminent" operating conditions. These conditions are not defined based on any objective metrics, but rather apparently are triggered based solely on the subjective assessments of the relevant functional entity. This is potentially

Organization	Question 7 Comment
	problematic from a compliance and practical perspective. Because these triggering conditions for action under the relevant section of the standard are ambiguous, this will be problematic in CMEP activities because the auditor and registered entity may have different opinions as to what "potential" and "imminent" conditions are. Accordingly, based on its opinion of what constitutes "potential" or "imminent", the auditor may believe the registered entity should have acted under the relevant section of the standard, whereas based on its opinion, the registered may not have taken the relevant action because it did not believe the relevant conditions existed. This has the potential to create significant problems during CMEP reviews. From a practical perspective, to mitigate the potential for related compliance issues, the registered entity may be motivated to take conservative action under the standard to avoid violations. In other words, the entity may determine the "potential" or "imminent" condition exists, thereby tirggering the relevant operating action (e.g. initiating EEA under R5) when conditions do not warrant such action. This potential scenario and the associated problems are exacerbated by the fact that system conditions are dynamic and such conservative behavior will be triggered by different operating conditions all the time so there will be no definition or transparency as to what constitutes "potential" or "imminent" conditions. This is not only problematic from an operational perspective, but also from a markets perspective, because market participants will have no clear understanding of what triggers the relevant emergency actions w/r/t "potential" or "imminent" conditions. Conversely, the objective actual EEA thresholds do establish known, transparent system conditions that trigger the relevant emergency operational actions. Furthermore, those thresholds were developed to define emergency conditions and distinguish them from normal operations. Accordingly, there is no need to create ambiguous and vague emergency condition triggers based on "potential" and "imminent' conditions. The NERC rules should allow normal/market rules to support system operations until such time as the objective, specifically defined emergency conditions arise, which should be the trigger for the relevant emergency operations. C. RC approval of the TOP and BA emergency plans The proposed standard requires TOPs and BAs to have RC approved emergency plans, and, accordingly, requires the RC to approve/disapprove the relevant entities' plans. ERCOT does not support the RC approval requirement. The relevant FERC directives (PP 547 and 548 in Order 693) do not require this. FERC stated that the RC should be an applicable entity under the standard, finding that "...the Commission is persuaded that specific responsibilities for the reliability

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	coordinator in the development and coordination of emergency plans must be included as part of this Reliability Standard." (emphasis supplied). Thus, the Commission explicitly found that the role of the RC is to facilitate coordination in the development of other entities' plans. Thus, the proposed standard's RC approval requirement is not required by Order 693 and isn't necessary or appropriate. The RC should review and comment on the emergency plans of TOPs and BAs in their regions to foster coordinated, efficient and effective emergency operations, but they should not have approval authority. Imposing an approval requirement inappropriately inserts third party involvment in the actionable obligations of another entity, which raises practical as well as compliance issues. Accordingly, the RC approval requirement should be changed to a review and comment RC action. RequirementsR1.2.1 - Including the obligation to include system conditions in the notification is inappropriate. "System" is defined in terms of generation, transmission and distribution. How is the LSE or BA going to know system conditions, which, by definition includes transmission and distribution. And if it's an LSE, how will they know generation conditions? The notice should just be to inform the RC that it is in an Operating emergency. R1.2.3 - Rather than saying cancellation or recall, why not just say "Management of Transmission and generation outages"? Cancellation / recall seems too prescriptive and implies full cancellation or recall of an outage. Couldn't there be other options - e.g. partial recall? R2.4.1 - The items listed are not emergencies, which is how it reads. Rather they are considerations in mitigating emergencies. R2.4.4 - This implies that the BA has to research and be aware of all such programs. What if a program is missed or the BA is not aware of one? Why can't this be captured under public appeals? Also, what is a "necessary" energy reduction? Is it relative to the emergency shortfall or the number in the government program? 2.4.5 - What is reduction of internal utility energy use? Is it referring to energy reduction of the BA? if it is relative to third parties it is inappropriate. Even if it is relative to the BA at issue it is not appropriate. The plan should be related to external operational considerations. This should not be dictating internal entity business practices. 2.5 - Replace “Strategies” with “Policies” for coordinating EOPs.R4 - Should be revised to say "as soon as practical as determined by the RC" to make it measurable. The intent of the revision is to mitigate the ambiguity associated with the general "as soon as practical" timing requirement for the notice by defining it explicitly in terms of the RC determination to issue the notice when it is feasible/practical. This mitigates the potential for different subjective opinions on what this means

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	between the CEA and registered entity in the context of CMEP activities. Attachment 1 - Section B - Introduction - Delete the first part of the first sentence. It should just say there are four EEA levels. Also, the last sentence is unnecessary and confusing. EEA is an operating practice, just limited to emergencies. Delete the entire sentence. EEA 1 - Delete "and is concerned about sustaining its required Operating Reserves." This is ambiguous and creates potential audit problems. Make the trigger relative to an objective metric, which is achieved by the first part - i.e. all generation is committed. Response: The EOP SDT has reviewed your comments and made the following changes: The Standard was modified so that Load is not shed to maintain reserves. The SDT removed the requirement to have the Operating Plans approved by the Reliability Coordinator, they are now reviewed by the Reliability Coordinator. The term "System" was removed from the notification process in Requirements R1 and R2. The SDT modified the requirement so that is now states: "Management of Transmission and generation outages," as suggested. Timing requirements were added to the requirement to remove "as soon as practical." The term "Strategies" was replaced with "Processes" in Requirements R1 and R2. The SDT retained in the standard the terms "potential" and "imminent" in the Attachment 1 and the new Requirement R6 and believes these terms are appropriate. The SDT retained the reduction of internal utility energy; and if not applicable in your region, can be stated as so, but may be used in other regions. The SDT believes that the last sentences contained in EEA 1 are still valid.
ISO/RTO Cojuncil Standards Review Committee	A. We do not agree with the proposed revision to the definition for Energy Emergency. The phrase "has exhausted all other resource options" is unnecessary but begs the question on what are these other options. Further, since LSE is no longer referenced in any of the requirements and hence energy emergency conditions are now generally linked to a BA, the reference to LSE should also be removed. We therefore suggest the definition be revised to:Energy Emergency - A condition when a Balancing Authority can no longer meet its expected demand/resource/interchange obligations. B. Requirement R1: We propose the following revision to avoid ambiguity and to add clarity:1.1 Simply change it to Emergency Operating Plan roles and responsibilities since "activate and implement" are provided in the emergency operating plan itself.1.2 Replace "strategies" with "procedures" as the latter is more specific and can better facilitate compliance assessment1.2.7 We

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	do not see the need to specify “extreme weather conditions”. The TOP needs to mitigate adverse reliability impacts caused by any reasons - parallel flows, heaving loading caused by demand exceeding forecast, transmission facility forced outages, etc., not just extreme weather conditions. Suggest to remove 1.2.7 since this is already covered by the other parts.1.3 Suggest replacing “strategies” with “process” as the latter is more specific and can better facilitate compliance assessmentC. Requirement R2: We propose the following revision to avoid ambiguity and to add clarity:2.1 Simply change it to “Emergency Operating Plan roles and responsibilities” since “activate and implement” are provided in the emergency operating plan itself.2.4 Replace “strategies” with “procedures” as the latter is more specific and can better facilitate compliance assessment, and add the phrase “the following measures” to clarify that Parts 2.4.1 to 2.4.9 are the possible mitigating measures; and delete Part 2.4.9 since this is already covered by the other parts.2.5 Suggest replacing “strategies” with “process” as the latter is more specific and can better facilitate compliance assessmentD. Requirement R4 is not measurable since there is no clear yardstick for “as soon as practical”. While a time period may be subject to different views, we nevertheless suggest the SDT consider revising it to “shall notify, as soon as practical but no later than 5 minutes after receiving the notification unless conditions do not permit such communications,” to put a bound on the time frame to support compliance assessment. Note that ERCOT does not support this comment (above).E. The wholesale replacement of “Energy Deficient Entity” with “Requesting BA” results in some inconsistency with Condition (1) in the General Responsibility A.1 of Attachment 1, which indicates that an RC may initiate an EEA on its own request. Clearly, an RC will likely issue an EEA when it identifies that a BA(s) in its RC Area is anticipating or experiencing an energy deficiency. Nonetheless, the use of “Requesting BA” only in the rest of Attachment 1 fails to address the cases where a BA is energy deficient but it does not request its RC to initiate an EEA; rather, it’s the RC that initiates the EEA before being requested. We suggest that the SDT consider replacing “Requesting BA” with “Energy Deficient BA” or simply reinstate the phrase “Energy Deficient Entity”. We further suggest that “Energy Deficient BA” be defined within Attachment 1 by adding a sentence after the first sentence in the “Introduction” section as follows: “The BA who is experiencing an Energy Emergency is referred to as an “Energy Deficient BA.” EOP-011 R1.2 and R2.4 should include the phrase to ‘include the applicable elements’ and remove the phrase ‘at a minimum’. This would be consistent with the previous language contained in existing EOP-001 R4

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	and allow for solutions that do not exist or are not ‘applicable’ in certain areas.Also we are wondering about the word ‘impact’ in Part 1.2.7 and 2.4.9. Impact is not a measurable word to aid compliance assessment.F. The term Load-Serving Entity been deleted from R5 and Attachment 1 but it has not been deleted from the definition of “Energy Emergency.” The term also continues to appear in the shaded area right below the definition of “Energy Emergency.” We suggest deleting the term everywhere it appears.G. In the Purpose, R1, and 1.2.1, the word “operating” that appears before “Emergency” or “Emergencies” should be deleted, as it unnecessary. Same comment applies to VSLs for R1 (delete “operating” before “Emergencies” and before “Emergency”).H. In 1.2.2, the word “control” should not be capitalized because “Voltage Control” is not a defined term.I. The word “and” should be deleted at the end of 1.2.7, if this part is retained (please see our comment under 7B, above. If the SDT’s goal is to have 1.3 be at the same level as 1.2 then the “and” is not necessary.J. The SDT has indicated in the Rationale for R1 that “Emergency Operating Plan” is not a newly-defined term but that two defined terms (“Emergency” and “Operating Plan”) are being used. Having the two terms used together creates a false assumption or expectation that “Emergency Operating Plan” is a defined term. We therefore suggest to either: Define the term “Emergency Operating Plan as: an Operating Plan that addresses Emergencies.” , or,Revise the standard to replace “Emergency Operating Plan” with “Operating Plan for Emergencies”.K. Compliance 1.1 - It is not necessary to repeat the definition of Compliance Enforcement Authority. A reference to the NERC Rules of Procedure is sufficient. The benefit is that, if the definition ever changes there, it will not have to be changed here. Therefore, 1.1 under Compliance should simply say: “Compliance Enforcement Authority” has the meaning ascribed to it in the NERC Rules of Procedure. L. For greater consistency, we suggest that the term “declare” be used throughout the Standard whenever Energy Emergency Alerts are discussed: (i) R5 - change “shall initiate an Energy Emergency Alert” to “shall declare an Energy Emergency Alert”; (ii) R5 Rationale: change “initiated” to “declared”; (iii) M5: change “initiated” to “declared” (also make corresponding changes in VSL section for R5); (iv) Attachment 1, A.1: change “Initiation by RC. An Energy Emergency Alert (EEA) may be initiated only by a RC” to “Declaration by RC. An Energy Emergency Alert (EEA) may be declared only by a RC.”M. The drafting team should consider removing EOP-011 R4 since it is redundant to the following requirements: - IRO-015-1 R1 requires RC’s to communicate notifications that impact neighboring RC’s- EOP-002-4 R2 requires BA’s to

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	communicate notifications that impact neighboring BA's- TOP-001-2 R5 requires TOP's to communicate notifications that impact neighboring TOP'sN. Attachment 1: - A. 1: Replace "RC's own request" with "RC's own initiative"- 2. Replace "reliability area" with "the RC Area"- Section B, Introduction: Suggest to remove the last sentence since it is unnecessary and confusing. EEA is an operating practice, just limited to emergencies. - EEA 1, Circumstances: Suggest to remove the last part "and is concerned about sustaining its required Operating Reserves." This part is ambiguous and may create audit problems; it makes trigger relative to an objective metric, which is already achieved by the first part. i.e. all generating resources are already committed.- EEA 2, Circumstances: We suggest delete "Requesting BA has implemented its approved Emergency Operations Plan." since declaring EEA (which has 4 levels) is part of the BA's Emergency Operating Plan per Requirement R2, which it is still implementing but not yet completed.- EEA 2, Section 2.4: Suggest to revise "return the Transmission element that may relieve" to "return any transmission elements that may relieve".- EEA 2 - Section 2.5: Suggest to revise the first sentence to "Before an EEA 3 is declared, the requesting BA...."- EEA 2, Section 2.5.1: The added language of "not being held for contingency reserves" is confusing (e.g. does it qualify peaking units, peaking and quick start or all gen) and does not appear to be needed. The sentence states that it only applies to generation that is "capable" of being on line. This implicitly excludes gen being held back for some other reason. Therefore, we suggest removing that last part "not being held for contingency reserves".- EEA 3, Section2.5.2: Suggest to delete "within provisions of any applicable agreements", which is potentially restricting and confusing because not all DSM is via agreements. It should simply states "Initiate all relevant DSM that is capable of being dispatched/utilized." Also, for reasons noted above, delete "not being held for contingency reserves". - EEA 3, Section 3.4: Should the TOP be TO, whose facility could be affected by the SOL/IROL reevaluation?- EEA 3, Section 3.4.1: This Section does not seem to be required since a BA is obligated to follow an RC's directive anyway.- EEA 3, Section 3.5.1: Suggest to clarify the role and sequence by replacing "that an alert has been downgraded" with "to downgrade the alert". Response: The EOP SDT has reviewed your comments and made the following changes: The term "Strategies" was replaced with Processes in Requirements R1 and R2. The SDT has removed the "as soon as practical" with a set time to make the requirement measureable. The SDT has replaced the term "requesting BA" in Attachment 1 with "energy deficient BA." The SDT made

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	changes to the standard replacing "initiated" to "declared" where they believe it was warranted. Voltage control was removed from the requirements, as suggested. The term "Emergency Operating Plan" was modified to "Operating Plan to mitigate Emergencies." The SDT modified the EEA 2 Section 2.5.1 and EEA 3 Section 3.4, as suggested. The SDT retained in the standard the proposed definition. The SDT did not modify the Compliance Statement, this is used by NERC in its templates and is part of all standards.
Associated Electric Cooperative, Inc. - JRO00088	AECI Supports SERC OC Review Comments comments for Item 7, and provides the following additional comments for SDT consideration: FOR EOP-011-1: CONSIDER: AECI recommends that future EOP-011-1 postings conform with other NERC draft standard postings that position each requirement's rationale box immediately preceding the corresponding requirement. RATIONALE: Not only does this help reviewers to check Measures against corresponding Requirements, it appears to be more consistent with NERC SDT's normative practice. FOR EOP-011-1 R2 PARTS 2.4.2...2.4.8: CONSIDER subjugating parts 2.4.2 through 2.4.8, as parts 2.4.2.1 through 2.4.2.7, beneath a general 2.4.2 topic of "Load reduction resources" (AECI is not wed to this title). RATIONALE: a) Helps to clarify the nature of Public appeals", unless the SDT is expecting that future public appeals might include their voluntarily adding energy resources for the grid, and b) because part 2.4.9 is substantively different from the preceding topics of Generating resources and Load reduction resources. FOR EOP-011-1 ATTACHMENT 1 PART 3.4: REPLACE: "of the TOP whose equipment" WITH: "of the TOP whose TO equipment" AND REPLACE: "by the TOP whose equipment" WITH: "by the TO whose equipment" RATIONALE: TOs actually own the equipment at risk, but TOPs would typically serve as the middle-man in these conversations, although they may at times have pre-determined formulas provided by the TO. Either way, this suggested language should work. Response: The EOP SDT has reviewed your comments and have inserted Transmission Owner, as suggested. The SDT considered modifying Requirement Part 2.4.2 as suggested, but retained the format as shown in the current draft believing both achieve the same intent in the standard.

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Puget Sound Energy	As defined in the NERC Glossary of Terms, the term "Emergency" is quite broad. As the standard is currently structured, an entity's Emergency Operating Plan could be implemented regularly, with a resulting need to demonstrate compliance with the plan's requirements during many events, regardless of the events' potential to significantly impact the BES. To address this impact, the SDT could consider limiting the instances when an entity is required to implement the plan in some way - either by using other defined terms that include a measure of significance (for example, a combination of "Energy Emergency" and "Adverse Reliability Impact" (as that term was approved by the BOT on 08/04/2011) would reflect more significant events) or by listing the types of events that require implementation of the plan (instances of manual or automatic load shedding, entry into an energy emergency condition, etc.). EOP SDT Response: The SDT reviewed the comments and did not make any changes. The SDT believes that the proposed standard allows for the entity to determine when the conditions exists and is able to define them in the Operating Plan to mitigate Emergencies.
American Transmission Company LLC	ATC agrees with the SDT's addition of the term "Operator-controlled" preceding the language "manual Load shedding" in Requirement R1, Sub-Requirement 1.2.6., however, ATC offers the following recommendations for added clarity and to further align the requirement to the rational given for Requirement R1.Currently Drafted Sub-Requirement from Standard EOP-011-1 (text below)1.2.6. Operator-controlled manual Load shedding plan coordinated to minimizethe use of automatic Load shedding;---ATC recommended revisions to Sub-Requirement R 1.2.6:(1) ATC recommends adding the text "Loads with" after "the use of" in Sub-Requirement 1.2.6. above. It would read as follows:R 1.2.6 "Operator-controlled manual Load shedding plan coordinated to minimize the use of Loads with automatic Load shedding";(2) Alternatively, ATC recommends the following change be made to R1.2.6 where "use of" is replaced with "overlap with". It would read as follows:R 1.2.6 "Operator-controlled manual Load shedding plan coordinated to minimize the overlap with automatic Load shedding;ATC believes either of these recommended revisions provides clarification regarding the SDT's intent for Sub-Requirement 1.2.6, as defined in the Rationale for Requirement R1.

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	EOP SDT Response: The SDT reviewed the comments and made changes to these requirements. The SDT believes it has captured the intent of your recommendations.
CenterPoint Energy Houston Electric, LLC	CenterPoint Energy appreciates the efforts and the commitment of the SDT and the opportunity to provide the following additional comments: 1) CenterPoint Energy recommends that the phrase “for times when an Emergency has occurred” be added to M1 and M2 of EOP-011-1 draft 2, when referencing operator logs and voice recordings. This is to mirror EOP-011-1’s draft RSAW, where under the “Evidence Requested” section of R1 and R2, the guidance states “Evidence of activation, such as operator logs, voice recordings, or other communications, for times when an Emergency has occurred.” 2) If the SDT retains the RC-approval approach, CenterPoint Energy is concerned that the language in Requirement R1 restricts TOPs to one single Emergency Operating Plan. CenterPoint Energy believes that TOPs should be able to utilize multiple plans to address R1, as long as the plans in aggregate include all the required elements. Thus, R1 should be revised to state: “Each TOP shall develop, maintain, and implement one or more Reliability Coordinator-approved Emergency Operating Plan(s) to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan(s), in aggregate, shall include the following elements:”. 3) CenterPoint Energy believes R1 Part 1.1 is unnecessary. TOP-001-1a Requirement R1 states that TOPs have the responsibility and clear decision-making authority to take whatever actions necessary to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies. TOP 001-1a R2 also states that, “Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment, shedding firm load, etc.” Further declaration of roles and responsibilities are unnecessary. CenterPoint Energy recommends R1 Part 1.1 be deleted. 4) CenterPoint Energy believes R1 Part 1.2.2 is duplicative of various existing requirements. TOP-004-2 R6 already requires TOPs to have policies and procedures that address monitoring and controlling of voltage levels that impact reliability. Additionally, VAR-001-3 R1 and R2 require TOPs to have sufficient reactive resources for Contingency conditions and to have formal policies and procedures for monitoring and controlling voltage levels “under normal and contingency conditions”. Furthermore, voltage control as proposed in the draft standard is not part of the currently effective EOP-001 Attachment 1, and so does need to be addressd within EOP-011. CenterPoint Energy believes Part 1.2.2 is unnecessary and should be deleted from EOP-011-1. 5) CenterPoint Energy

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	believes the “extreme weather conditions” referenced in R1 Part 1.2.7 is vague, and it would be challenging for TOPs and auditors to interpret what qualifies as “extreme”. CenterPoint Energy believes that not all events of “extreme” weather result in emergency conditions requiring special mitigation strategies. In addition the Company believes that various existing operational planning requirements are sufficient to cover preparedness for extreme weather, such as TOP-005-2a R2 and Attachment 1 and TOP-006-2 R4. Therefore, Part 1.2.7 is unnecessary and should be deleted. If, however, an “extreme weather conditions” requirement must be retained, CenterPoint Energy recommends Part 1.2.7 be revised to state: “Mitigation of reliability impacts of extreme weather conditions defined by the Transmission Operator.”6) CenterPoint Energy requests the SDT review the combined term “Transmission System”. CenterPoint Energy believes the definition of transmission system is well understood; however, using the capitalized term “System” (a combination of generation, transmission, and distribution components.)introduces a conflict with the meaning of the defined term “Transmission”. CenterPoint Energy recommends using the lower case term “system” in this instance. EOP SDT Response: The SDT reviewed the comments and added the suggested words to Measure M1 and M2. The RC approval approach was not retained and, therefore, this suggestion was not implemented. The SDT has retained the requirement on Roles and Responsibilities, it is important to understand who will be activating the Operating Plan to mitigate Emergencies. The SDT deleted Requirement Part R1.2.2, as suggested. The SDT retained the need for a process to be developed around extreme weather and did not make the suggested change. The SDT made the requested change by using the lower case term “system.”
PPL NERC Registered Affiliates	Comment on Requirement 2, section 2.4.6 - We suggest the removal of “Customer Fuel Switching” from the list. It is unclear what a strategy titled “Customer Fuel Switching” would entail.Comment on Attachment A, section B.2.5 - The first sentence begins with “Before declaring an EEA 3, the requesting BA must...” This makes it sound as though the BA can declare an EEA 3. The sentence should read, “Before requesting an EEA 3, the BA must...”Comment on Attachment A, section B.2.1 - This section is preceded by the sentence, “During an EEA 2, RCs and BAs have the following responsibilities:” The first sentence of 2.1 states that, “The requesting BA shall communicate its needs to other BAs and market participants,” but it does not describe how the BA is to make this

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	communication. It sounds as though this is a real time communication between the requesting BA and market participants (PSEs) but over what medium, and what obligation do the PSEs have to proactively look for communications from requesting BAs? Market participants (PSEs) may not have access to the RCIS website. Comment on Attachment A, section B.3.4.1 - The words “must agree that” in the first sentence of this section should be removed to reflect that the requesting BA does not have any options in the defining the prerequisites for SOL/IROL revision. We recommend the following change:”The requesting BA will, upon notification from its RC of the situation, take whatever actions are...”Comment on Attachment A, section B.2.5.1 - The mention of “all available generation units” is unnecessary as this is previously mentioned as a circumstance of an EEA1 in section B.1.Comment on Attachment A, section B.2 - Is this intended to mean that operating reserves should be maintained while the entity can’t meet the customer’s expected energy requirements? Operating reserves would not be maintained at the expense of cutting firm load. EOP SDT Response: The SDT reviewed the comments and has removed the “Customer Fuel Switching,” as requested.
Duke Energy	Energy Emergency Definition: Duke Energy suggests adding “or Balancing Responsibilities” at the end of the definition. As currently written, the definition suggests that a Balancing Authority carries Load Obligations which is not accurate. A Load Serving Entity does indeed have Load Obligations, but a Balancing Authority does not, and is only responsible for Balancing in its BA Area. Our suggested revision is as follows:Energy Emergency: A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its respective Load Obligations or Balancing responsibilities. R1 and R2 should not have “Reliability Coordinatorâ€approved” included in the requirement. (Please see comments associated with Question 3.)Below are Duke Energy’s suggested revisions to Attachment 1:Attachment 1 EOP-002-3.1/ EOP-011-1 modificationsEnergy Emergency AlertsIntroduction This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator (RC) to communicate the condition of a Balancing Authority (BA), which is experiencing an Energy Emergency.A. General Requirements 1. Initiation by Reliability Coordinator. An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator’s own request, or 2) upon the request of a BA or LSE.2. Notification. A Reliability Coordinator who declares an Energy

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	Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The RC shall notify the other RCs via RCIS, and the BAs and TOPs in its Reliability Area of any change in EEA level.B. Energy Emergency Alert LevelsIntroductionTo ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established four levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining Energy Emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.4. EEA 1- All available resources in use to serve firm load, firm transactions, and required reserves.Circumstances: The Requesting BA is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves. During EEA 1, the Requesting BA has the following responsibilities to mitigate the energy emergency progressing to an EEA 2: o Implement its Emergency Operating Plan o Curtail non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) as needed to balance resources and demand. o Curtail non-firm end-use loads including Demand Side Management within the BA Area in accordance with applicable contracts (other than those designated to be shed to meet reserve requirements) as needed to balance resources and demand. o Implement conservative operations protocols within its BA Area to reduce risk of errors impacting resource availability.5. EEA 2 - Utilization of Contingency Reserves and emergency assistance.Circumstances: The Requesting BA is no longer able to balance its resources and the demand of firm loads and firm transactions without utilization of its Contingency Reserves.During EEA 2, the Requesting BA has the following responsibilities to mitigate the energy emergency progressing to an EEA 3: o Complete EEA 1 actions. o Curtail remaining non-firm wholesale energy sales. o Curtail remaining non-firm end-use loads including Demand Side Management within the BA Area in accordance with applicable contracts. o Implement use of Contingency Reserves to meet firm load obligations o Implement emergency

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	energy purchase transactions. o Issue public appeals to reduce demand o Request voltage reduction o Prepare to shed firm load2.2 Declaration period. The Requesting BA shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. During EEA 2, the RC has the following responsibilities to mitigate the energy emergency progressing to an EEA 3:2.3 Evaluating and mitigating Transmission limitations. The RC shall review Transmission outages and work with the TOP to see if it's possible to return the Transmission Element that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).3. EEA 3 - Firm Load interruption is imminent or in progress. Circumstances: The Requesting BA is, or projects that it will, no longer able to balance its resources and the demand of firm loads and firm transactions, and foresees a need for possible interruption of firm Load and firm transactions. During EEA 3, the RC and Requesting BA have the following responsibilities:3.1 Continue actions from EEA 2. The Reliability Coordinators and the Requesting BA shall continue to take all actions initiated during the EEA 2.3.2 Declaration Period. The Requesting BA shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. 3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the Requesting BA. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists or as allowed by the Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised: 3.4. Requesting BA obligations. The Requesting BA must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding. 3.5 Returning to pre-emergency conditions. Whenever energy is made available to a Requesting BA such that the transmission systems can be returned to their pre-emergency SOLs or IROLs condition, the Requesting BA shall request the Reliability Coordinator to downgrade the alert level. Alert 0 - Termination. When the Requesting BA is able to maintain its required reserves and balance its resources and demand, it shall request its RC to terminate the EEA.

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	The SDT reviewed your comments and appreciates your suggestions on modifications to Attachment 1. While not all recommendations were implemented, the EOP SDT did modify Attachment 1 substantially based on your submittals and those from the industry.
Exelon Companies	Exelon agrees with the majority of the substantive changes proposed but encourages the SDT to be as clear as possible with language in the Requirements when drafting the next revision. We note that by removing processes and procedures from R1 for example, and leaving only strategies, an entity may not be able to document the existence of a strategy to implement the Program. The RSAW, for example refers to an auditor verifying that procedures were implemented not that an entity had a strategy. We are generally uncomfortable with the language regarding evaluation of strategies and the use of “at a minimum”. We also note that the Time Horizon for R1 and R2 is Operations Planning (have a plan) and Real Time (implement elements of the plan / strategy). For those Requirements that are Real Time, we question the ability for some of them to be implemented. For example, the requirement to cancel transmission or generator outages in response to an Energy Emergency; the likelihood of bringing a generator or transmission line back into service from an outage in response to a real time emergency is very low. We would like the DT to consider whether this element belongs in an entities plan. We believe the more generic requirements in EOP-001-3 R2 can provide guidance in this area. Also, the requirement to mitigate extreme weather was subject to extensive review and determined not to require a standard. There is NERC Guidance addressing this. The SDT reviewed your comments and appreciates your suggestions on the RSAW and understands that the auditor should see if the plan has the process in place; and that during implementation of the plan, did the entity carry out the process if an Emergency dictated it. The SDT agrees that the success of the action in the plan such as calling for generation that is an outage, while not successful should not be the focus of the audit, but instead did you follow the process. The SDT agrees that there exists NERC guidance on extreme weather, but the SDT felt it is necessary that a process be in place so that an entity would address extreme weather in its company.
Florida Municipal Power Agency	FMPA supports the comments submitted by FRCC.

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Ameren	From our understanding there seems to be no mandated timeframe for what constitutes maintenance of TOP or BA emergency plans with respect to load shedding. We ask the drafting team; once the plan is approved by the RC, does the TOP or BA need to review or submit a plan every year, once every three years, or never? The SDT does not believe that a set timeframe needs to be established on maintenance, that the industry should be able to determine that based on the plan in which they have written to be in compliance to Requirements R1 and R2.
Xcel Energy	In section 3.2 of the Attachment 1, we believe the revised wording below provides additional clarity:3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be [prepared] to shed an amount of firm Load in order to meet its Operating Reserve requirement. The SDT has removed 3.2 of Attachment 1.
PacifiCorp	PacifiCorp recommends the Standard Drafting Team replace the word “Strategies” with “A process” in R1.3 and R2.5 for coordinating Emergency Operating Plans with impacted Balancing Areas and Transmission Operators. PacifiCorp believes a process for Plan coordination, combined with evidence such as communication documentation, would provide improved compliance evidence, based on the Measures described in M1 and M2. The SDT has replaced “strategies” with “processes,” as recommended in Requirements R1 and R2. The SDT also eliminated Requirements R1.3 and R2.5 and placed the coordination on the Reliability Coordinator in Requirement R3.
The FRCC Operating Committee (Member Services)	R1 and R2 should not have “Reliability Coordinator-approved” included in the requirement. (Please see comments associated with Question 3.)R1.2.6 and R2.4.8. We agree with the rationale but would like additional language added to the standard to clarify the intent. Adding a “(UFLS and UVLS as applicable)” after automatic Load Shedding would be beneficial since the rationale box will not be included in the standard.Creating a new defined term would be preferred over the

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	combining of two separate defined terms (as noted in the Rationale for Requirement 1). It will add confusion to future readers when combined terms are used without specifically noting the combining of those terms. The SDT has removed from Requirements R1 and R2 the Reliability Coordinator-approved statement. The SDT did not believe it necessary to add UFLS and UVLS after Requirement Part R1.2.6 and Requirement Part R2.4.8 due to other changes made to those requirements. Where two defined terms were used side-by-side, the SDT tried to remove those occurrences to eliminate confusion.
JEA	R1&R2 should state that only "applicable" parts need to be included. Voltage control should not be part of the emergency plan and is already covered by standards TOP004-R6 and VAR001-3 R1. The SDT has made the modifications, as requested.
MRO NERC Standards Review Forum	R1.2.3, Transmission is capitalized and generation is not, not sure if this is a type-o or not. R2.4.6, Customer fuel switching. The NSRF questions why this should be in an Emergency Operating Plan, since the customer will most likely be under 2.4.7, Demand response. As a BA, there are contracts with customers and if they elect to not be a signatory to those contracts, they always have the right to drop utility power and go on their owned and operated generation during the time of no utility power. Plus customers that own their own generation are excluded from the NERC Standards if they meet Exclusion E2 of the new BES definition. Recommend R2.4.6 be deleted from the R2. In addition to the above justification, there is no clear definition of “customer”. Could a customer be a single house hold that has a back up generator legally tied to their main circuit panel? This is another reason why R2.4.6 should be deleted. The SDT removed Customer fuel switching from the standard.
DTE Electric	R1: The TOP should not be responsible for cancellation of generator outages. This function should remain being assigned to the BA. The current standard NERC EOP-002-3.1 has the BA postponing equipment maintenance.EEA2 Section 2.5.2: Demand-Side Management is a term defined in the

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	NERC glossary. Ensure the hypen is in place for both uses of the term.Attachment 1B Introduction, first sentence: change "four" to "three". The SDT appreciates your comment and understands that the TOP will not be the one responsible for the cancellation of the generation, but they do need a process in place if generation needs to be cancelled during a Transmission Emergency. The SDT has corrected the Demand-Side Management term in the document and modified the levels to three.
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	R1: We appreciate the SDT's clarification of the term Emergency Operating Plan. The NERC Glossary defines Emergency as, "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System." Southern continues to believe that the definition of Emergency as applied in EOP-011-1 is too broad. An emergency is considered as an operating condition which has not been studied and for which no mitigating plan has previously been developed. For example, having a contingency occur which was studied and for which a post-contingency mitigation plan has been developed, communicated, and can be implemented prior to an SOL exceedance is not an emergency even though it may require immediate manual action by an operator. Similarly, an IROL which can be mitigated prior to Tv as required by IRO-009 should not be considered an Emergency regardless of what actions the IRO-009-1, R1's Operating Process/Procedure/Plan requires. An Emergency Operating Plan, particularly as it relates to transmission and the TOP should be limited to multi-element contingencies due to things like weather, differential relay operations, relay failures, etc. or to other unstudied states where a potential or actual SOL exceedance needs to be managed as quickly as possible.In addition, Southern recognizes that R1 Rationale states that the Transmission Operator can note R1 Parts are "not applicable" in their plan. However, Southern requests that the SDT add that verbiage in the requirement (R1) rather than relying on rationale boxes that are deleted in final versions of the standards or other supporting documents:"Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, if applicable, the Emergency Operating Plan shall include the following elements:" Southern requests more guidance on the elements listed in R1.2. Are the strategies listed unique to emergency operations? For example, is the

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	Voltage control listed that which is unique to an emergency or also a part of normal voltage control procedures? If these strategies are unique to an emergency, Southern suggests that the SDT add more clarity by removing the sub-bullets and revising the requirement to state:"R1.2. Strategies that are not included in normal operating procedures that are used to prepare for and mitigate Emergencies; " R1.2.6. Southern believes this requirement needs additional clarity by removing coordinated as revised:"Operator-controlled manual Load shedding plan designed to minimize the use of loads that are a part of automatic Load shedding plans;"R2: Southern also believes "if applicable" should be included in the Balancing Authority's Capacity and Energy Emergency Plans as stated in the draft RSAW. If this designation is significant enough to include in the RSAW then it should be stated in the requirement. (see similar comment for R1 above)R2.3 Southern suggests modifying this requirement to be consistent with R5 and Attachment 1 language where a BA requests their RC to initiate an EEA rather than the BA declare an EEA. Southern suggests the following revision: " Criteria to request an Energy Emergency Alert, per Attachment 1;"R2.4.1 Southern suggests adding "if applicable" to this requirement because a BA may not be the sole function that has knowledge of all information listed in the sub-bullets for R2.4.1.R2.4.2, R2.4.3, R2.4.4: Southern requests the SDT to provide guidance on each of these strategies. Are these specific to certain regions or customers and not continent wide? For example, what is the difference between a Voluntary Load reduction and a Public Appeal? Southern requests the SDT to provide examples. R4: Southern would like to see more guidance on determining what "impacted" means since it can be a subjective term and therefore makes the requirement less measureable. In R4, Att. 1 section 2.3, Att. 1 section 3.3, Att. 1 section 3.5.1, and Att. 1 section 0.1, the wording inappropriately intertwines notification/communication from an RC to BAs and TOPs in a manner contrary to current, and in fact very reliable, practices used today . In these locations, the terminology "other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators" or similar words are used. In practice, based on the established hierarchy of RCs and their associated BAs/TOPs, an RC will notify and communicate with other RC's and with the BAs and TOPs in it RC Area. To require an RC to notify/communicate with a non-associated "impacted" BA/TOP as the current draft's wording implies has the potential to cause confusion and is not a relationship which operators are accustom to. BAs/TOPs should be expected to communicate with one and only one RC to maintain the "command and control" hierarchy that is currently used and,

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	in our opinion, is expected by FERC.We suggest alternate wording for “other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators” or similar references to clearly maintain the established RC to BA/TOP communication hierarchy:An RC will notify “impacted Balancing Authorities and Transmission Operators in their own RC Area as well as other impacted Reliability Coordinators who are expected to notify impacted Balancing Authorities and Transmission Operators in their RC Area”Attachment 1 Section 2.3 - Southern suggests the following revision to limit the scope of BA responsibilities to contact requesting BAs and to clarify the appropriate communications channels :” A neighboring BA with available resources and that has contractural agreements in place with a requesting BA shall coordinate with it’s RC as appropriate to provide assistance to the requesting BA.”Attachment 1 Section 2.5 Southern suggests that the title “BA actions” be updated to reflect “Requesting BA actions” to reference the appropriate BA. Southern also suggests that the word choice be updated to reflect that a BA can not declare an EEA as indicated the Initiation Section of Attachment 1 and EOP-011-1 R5.Attachment 1 Section 2.5.2 - Southern asks the SDT to consider replacing “curtailed” with “activated” to improve word choice and add clarity. The use of “curtailed” when referring to DSM can be very confusing.Attachment 1 Section 3.2 - Southern requests for the SDT to consider modifying this language because some BAs may not participate in an Operating Reserve sharing program, and to explicity state that it is not required to shed Load to maintain normal Operating Reserves during this abnormal situation. Southern believes that the following revision should be made to add guidance:”Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through an Operating Reserve sharing program, if applicable. In this situation, the requesting BA must be able to, but not required to pre-contingency, shed an amount of firm Load in order to meet its Operating Reserve requirement. A BA may continue to carry reserves below the required minimum and plan to shed Load post contingency. EOP SDT Response: The SDT appreciates your comments and we have added to Requirements R1 and R2 “as applicable.” The SDT did not include the suggested language for Requirement Part R1.2 and Requirement Part 2.4, it believes that it is clear as written that this is for emergency situations and not during normal events. The SDT modified the Load shedding requirement based on industry comments and removed the term “coordinated.” The term “criteria” was removed from

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	Requirement Part 2.3 and was made consistent with Requirement R5 and the Attachment. Since ”If applicable” was added to Requirement R2, the SDT did not believe it needed to be added to those items in the requirement parts. The SDT appreciates the comments on “impacted” and has modified Requirement R4, which, in the new draft, is Requirement R5, such that the Reliability Coordinator is notifying its Balancing Authorities and Transmission Operators and neighboring Reliability Coordinators, thus removing the term “impacted.” The SDT modified in Attachment 1, Requirement Part 2.3 such that the Reliability Coordinators are sharing information and having the appropriate Balancing Authorities work together, as needed. In Attachment 1, 2.5 and 2.5.2 were modified, as requested. In Attachment 1, 3.2 was deleted.
SERC OC Review Group	R2 - For consistency with Part 1.1, remove ‘and implement’ from 2.1 (this is not struck on the redlined version, but it does show that it has been removed on the clean version).R2 - For consistency with R1, the content of 2.2 and 2.3 should be moved as sub parts below 2.4 instead of included as “stand alone” parts 2.2 and 2.3.R2- The requirement appears to use a newly capitalized term “Capacity”. This term is not included in the NERC Glossary of Terms currently posted. If the intent is to use the existing defined terms, Capacity Emergency and Energy Emergency, then the SDT needs to write the requirement accordingly. Attachment 1 Section A1 - review wording of item 2 for redundant use of ‘request’.Attachment 1 Section 3.4 - SDT should consider that Transmission Owner is more appropriate than Transmission Operator for the subject review of SOLs and IROLs. The comments expressed herein represent a consensus of the views of theabove named members of the SERC OC Review Group only and should not beconstrued as the position of the SERC Reliability Corporation, or its board or itsofficers. EOP SDT Response: The SDT appreciates your comments and has modified the standard to remove the term “implement.” The SDT has redrafted Requirement R2 and we believe we have captured your requested changes. We have included the Transmission Owner in Attachment 1, as requested, and reworded Item 2 to remove the redundant use of “request.”
Dominion	R2 - For consistency with Part 1.1; remove ‘and implement’ from 2.1 (this is not struck on the redlined version, but it does show that it has been removed on the clean version).R2 - For consistency with R1; the content of 2.2 and 2.3 should be moved as sub parts below 2.4 instead of

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	included as "stand alone" parts 2.2 and 2.3.R2- The requirement appears to use a newly capitalized term "Capacity". This term is not included in the NERC Glossary of Terms currently posted. If the intent is to use the existing defined terms, Capacity Emergency and Energy Emergency, then the SDT needs to write the requirement accordingly. EOP SDT Response: The SDT appreciates your comments and has modified the standard to remove the term "implement." The SDT has redrafted Requirement R2 and we believe we have captured your requested changes. We have included the Transmission Owner in Attachment 1, as requested, and reworded Item 2 to remove the redundant use of "request."
Tacoma Power	R2.3 needs to be revised to state "Criteria to request declaration of an Energy Emergency Alert per Attachment 1" EOP SDT Response: The SDT appreciates your comments and has modified Requirement Part R2.3.
ReliabilityFirst	ReliabilityFirst submits the following comments for consideration:1. Requirement R4 - ReliabilityFirst believes the term "as soon as practical" is ambiguous, does not provide any added value, and should not be used in standards. This term leaves the requirement open to interpretation and potential problems in compliance monitoring and enforcement. ReliabilityFirst recommends the following for consideration "Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify the impacted Reliability Coordinators, Balancing Authorities and Transmission Operators[, within 30 minutes of the start of the Emergency.]" This time frame of 30 minutes is used throughout similar standards and we believe it is applicable here as well. 2. Requirement R7 - ReliabilityFirst believes the term "as soon as practical is ambiguous, does not provide any added value, and should not be used in standards. This term leaves the requirement open to interpretation and potential problems in compliance monitoring and enforcement. ReliabilityFirst recommends the following for consideration "Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify the impacted Reliability Coordinators, Balancing Authorities and Transmission Operators[, within 30 minutes of the start of the Emergency.]" This time frame of 30 minutes is used throughout similar standards and we believe it is applicable here as well3. Requirement R9 - ReliabilityFirst believes there should a timeframe

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	associated with how long a Reliability Coordinator has to initiate a NERC Energy Emergency Alert following a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency. ReliabilityFirst recommends the following for consideration: “Each Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1[, within 30 minutes of request.]” This time frame of 30 minutes is used throughout similar standards and we believe it is applicable here as well EOP SDT Response: The SDT appreciates your comments and has modified the standard and removed the term “as soon as practical” and set defined times. The SDT does not believe that the now drafted Requirement R6 should have a set time since the notification timeframe is being handled in Requirement R5.
Seattle City Light	Seattle offers the following suggestions:For R1.2.1 "Notification to the RC to include current and projected System conditions when experiencing an operating Emergency": to keep the focus on reliability and minimize compliance traps, please add language about notifications such as ‘as soon as practical.’ The focus during an emergency should be on addressing the emergency, not on ensuring compliance activities. To date, auditors at times have focused on the exact timing of notifications while appearing to neglect the larger picture. Additional wording may help avoid such interpretations.For R1.2.2 Voltage Control, please clarify. In the current version of EOP-001 (specifically Attachment EOP-001-0b) voltage control is mentioned in ‘Load Management’ as voltage reductions. The new standard doesn’t give any direction. The ‘Rationale for Requirement’ states: "Requirement R1 Part 1.2. was added to this standard for the Transmission Operator to address strategies to prepare for and mitigate Emergencies using voltage control methods, which could include switching of capacitor and reactor banks, generator reactive output, and the use of synchronous condensers." As such this subrequirement seems like this is a new requirement - not a consolidation of the old requirements.For R1.2.6 and R2.4.8, "Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding": Please provide guidance in this subrequirement or the RSAW as to how such "coordination to minimize" would be evidenced and audited. Alternatively, reword the subrequirement to provide more specificity as to what is intended here. Without additional guidance, this seemingly minor subrequirement could

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	require more evidence than all the other subrequirements together while adding minimal BES reliability benefit.Regarding R1.3 "Strategies for coordinating Emergency Operating Plans with impacted TOPs and BAs" is excessively vague for a world-class Standard. Please provide additional guidance as to what is expected or delete as unecessary. Is an "annual exchange of plans" among impacted TOPs and BAs such a "strategy" or is something further anticipated? As written the subrequirement is reminiscent of a "version 0" best practice: it does not require anything other than that the plan list one or more strategies. It does not require that the strategies be implemented or followed, nor that they are effective or comprehensive strategies. If such activities and characteristics are deemed necessary for BES reliability then they should be required explicitly; if they are not necessary then the subrequirement should be dropped entirely. Standards are not the place for "nice to have" items. In the absence of additional information, Seattle recommends that R1.3 be deleted. The subrequirements of R2.4 for BAs are similarly vague and likewise should be clarified or deleted. EOP SDT Response: The SDT appreciates your comments but based on industry input, the term "as soon as practical," will not be added to Requirement Part R1.2.1. The SDT has removed the need for Voltage Control in the standard. The SDT has modified Requirement Part R1.2.6 and Requirement Part R2.4.8 based on industry comments. Requirement Part R1.3 and Requirement Part R2.4 have been deleted.
SPP Standards Review Group	Shouldn't the term "energy emergency" as it appears in the 5th line of the Rationale Box for its definition be capitalized?Also in the Rationale Box for the definition under IRO-005-3.1a, the SDT states that IRO-005-3.1a is being revised under Project 2014-03 TOP/IRO Revisions. This is not the case. Project 2014-03 is not working with IRO-005. The IRO Five Year Review Team moved requirements regarding notification from IRO-005-3.1a to IRO-008-1 and recommended retiring IRO-005. Project 2014-03 has made additional changes to IRO-008-1 but the changes proposed by the IRO Five Year Review Team have been incorporated into the latest revision of IRO-008-2 by Project 2014-03. The term energy emergency is not in either version of IRO-008. (This same comment applies to a similar section in the Proposed Definitions for the NERC Glossary of Terms document.)Terms such as 30-calendar days should be hyphenated.How does the drafting team propose to measure 'as soon as practical' in Requirement R4?The following comments are directed

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	toward Attachment 1.Changing the ‘should’ to ‘shall’ in the sentence in Section A.2 creates a conflict in that the Reliability Coordinator is now required to hold conference calls but the conditions under which those calls are to be held are not specifically defined by the phrase ‘as necessary.’ We recommend the drafting team return the language to the original language or provide the Reliability Coordinator with a list of conditions which would necessitate such calls. Also, see our comment in response to Question 6 regarding additional information on this issue.In the 5th line of the Introduction under Section B. EEA Levels, change ‘standard’ to ‘standards’.Insert an ‘an’ between ‘During’ and ‘EEA2’ in the line between the last bullet under Circumstances under Section B.2 and 2.1.Insert ‘to service’ between the ‘return’ and the ‘the’ at the end of the 2nd line of B.2.4.Insert an ‘an’ between ‘During’ and ‘EEA 3’ in the line between the bullet under Circumstances under Section B.3 and 3.1.See our comment on 3.2 in Question 5 above.Add RCs to B.3.3 to be consistent with B.2.2.Replace ‘SOLs or IROLs’ with ‘SOL or IROL’ in the 3rd line of B.3.5.The following comments are directed toward the Technical Justification document.The designation for footnote 4 should be a superscript in the next to last line on Page 3.The 2nd and 3rd bullets under EOP-002-2 are actually a continuation of the 1st bullet. The bullets, not the text, need to be deleted. EOP SDT Response: The SDT appreciates your comments and has removed the term “as soon as practical.”
Texas Reliability Entity	Texas RE recognizes the amount of work the SDT has put into this standard and applauds the team for successfully combining the existing Emergency Operations requirements into one single Standard. Much of the ambiguity has been eliminated and various inputs have been addressed well. However, Texas RE has a few concerns with the current draft which prompt a negative vote at this time. 1) The main focus of this standard appears to be energy and capacity emergencies. Are there other types of emergencies that need to be covered by emergency plans? For example, does the standard need to cover requirements if a TOP may need to declare a Transmission emergency if it is unable to mitigate an IROL or SOL violation?2) Requirements R1 and R2: EOPs are critical to the reliability of the BES and assurance that the plans are maintained is necessary. The mapping document on the 2009-03 project page shows that the requirement for a time based review/update of EOPs (from EOP-001-2.2.1b, Requirement R5) has been translated to EOP-001-1,

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	Requirement R1. However, the draft standard does not include a requirement for a TOP or BA to review/revise their EOPs on a specified periodicity. Therefore it is not measurable. Texas RE recommends the EOP SDT adding the following phrase to both R1.4 and R2.6: “Revise and review the EOP as needed but no less than annually.”3) The language for Requirements R1.2.6 and R2.4.8 states that operator-controlled Load shedding shall be coordinated to minimize the use of Automatic Load Shedding. That language is not in synch with the Rationale for Requirement R1 which states the goal is minimize the manual use of Loads armed for automatic Load shedding; recognizing that complete exclusion may not be possible. Texas RE recommends the EOP SDT revise the language in Requirements R1.2.6 and R2.4.8 to the following: “Operator-controlled manual Load shedding plan coordinated to minimize the use of Loads armed for automatic Load shedding;”4) Requirement R4: While agreeing with the change of practicable to practical in the requirement, Texas RE asserts that omitting a required notification “not to exceed” date allows a potential reliability gap. RCs, BAs, and TOPs need to know that Emergency notifications have taken place even if they were not directly involved in the Emergency, and they need to know relatively quickly. This communication can be assured by the addition of “but no later than seven days after the end of the Emergency” after “as soon as practical”. The addition would require a corresponding adjustment to the VSL.In addition, the Rationale for R4 states that it was an existing requirement in EOP-002-3.1 for BAs. It appears that the EOP-002-3.1 requirement being referenced here is Requirement R3, which required a BA experiencing an operating capacity or energy emergency to communicate system conditions to its RC and neighboring BAs. The requirement did not restrict the required communication to “impacted” BAs. Texas RE recommends the EOP SDT consider removal of the phrase “other impacted” RCs, BAs and TOPs and replace it with “neighboring” RCs, BAs and TOPs. Replacing “impacted” by “neighboring” is important since, among other reasons, the Emergency may have been resolved efficiently in that instance, but conditions may still exist for the Emergency to reoccur and the potential next Emergency may involve more TOPs and BAs than the previous Emergency. 5) Requirement R5: R5 states that an RC shall initiate an Energy Emergency Alert (EEA) when a BA in its area has a potential or actual Energy Emergency but does not address the RC responsibility in the event the BA has a Capacity Emergency. Requirement R2.2 requires that a BA having a Capacity Emergency notify the RC of that

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	Emergency. Texas RE requests clarification regarding the RC responsibility to take some action in the event of a BA Capacity Emergency. EOP SDT Response: The SDT appreciates your comments and discussed the need for some type of time requirement for review, but believes that the industry should determine how often they need to maintain their plan based on the processes included in the plan. The SDT revised Requirement Part 1.2.6 and Requirement Part 2.4.8 based on industry comment, and reflects your requested changes. The SDT modified Requirement R4 and has removed the term “impacted” and added “neighboring.” The SDT believes Attachment 1 defines the needed criteria in which to implement the levels of and Energy Emergency Alert.
Public Utility District No. 1 of Cowlitz County, WA	The District feels the SDT is progressing in the correct direction. However, concerning the changes made to Requirement R4, the District recommends the SDT review word usage of “practical” as it can be easily misunderstood. Its usage in “as soon as practical” is equivalent to “as soon as useful.” If this is the intent of the SDT, the District recommends “as soon as useful” due to the fact that “practical” is often confused with “practicable,” i.e., as soon as possible. The District appreciates the desire not to engulf BAs and TOPs with excessive or nuisance Emergency notices. EOP SDT Response: The SDT appreciates your comments and has removed the language “as soon as practical.”
Northeast Power Coordinating Council	The Drafting Team should revise the Evidence Retention section of this standard which is very specific requiring the retention of all versions of the EOP within the audit period. This is inconsistent with the allowed practice of maintaining detailed revision history within the current version. With the possible use of RAI to extend audit cycles (which could increase the time between TOP audits to more than 3 years), TOP and BA’s will be maintaining versions of EOP solely for backward horizon compliance monitoring. A more effective approach is to require the TOP and BA to retain the current version with revision history and utilize spot checking to monitor compliance. The wholesale replacement of “Energy Deficient Entity” with “Requesting BA” results in some inconsistency with Condition (1) in the General Responsibility A.1 of Attachment 1, which indicates

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	that a RC may initiate an EEA on its own request. Clearly, a RC will likely issue an EEA when it identifies a BA(s) in its RC Area is anticipating or experiencing energy deficiency. Nonetheless, the use of “Requesting BA” only in the rest of Attachment 1 fails to address the cases where a BA is energy deficient but it does not request its RC to initiate an EEA; rather, it is the RC that initiates the EEA before being requested. We suggest the SDT to consider replacing “Requesting BA” with “Energy Deficient BA” or simply reinstate the phrase “Energy Deficient Entity”.EOP-011-1 Parts 1.2 and 2.4 should retain the phrase to ‘include the applicable elements’ below, and remove the phrase ‘at a minimum’. This would be consistent with the previous language contained in existing EOP-001 R4 and allow for solutions that do not exist or are not ‘applicable’ in certain areas.Is “impact” a measurable word that should be in the standard? In sub-Part 1.2 and Part 2.5 the TOP and BA are required to coordinate with impacted TOP and impacted BA. Impacted could mean electrically affected by the EOP or it could mean having a role to play in executing the EOP. In R4 the ambiguity in impact is similar. Guidance or clarity is needed around this term.R2 - For consistency with Part 1.1 remove ‘and implement’ from Part 2.1 (this is not struck on the redlined version, but it does show that it has been removed on the clean version).R2 - For consistency with R1; the content of Parts 2.2 and 2.3 should be moved as sub-Parts below Part 2.4 instead of included as standalone Parts 2.2 and 2.3.R2- The requirement appears to use a newly capitalized term “Capacity”. This term is not included in the NERC Glossary of Terms currently posted. If the intent is to use the existing defined terms, Capacity Emergency and Energy Emergency, then the SDT needs to write the requirement accordingly. Regarding requirement R4, first, requirement R4 is not measurable since there is no clear yardstick for “as soon as practical”. This concept was a challenge in the development of FAC-003-3. In FAC-003-3 the phrase “without any intentional time delay” was used, or consider adding language similar to TOP-001-2 requirement R5 that uses the phrase “unless conditions do not permit such communications.” Secondly, the Drafting Team should consider removing EOPâ€011 R4 since it is redundant to the following requirements:- IRO-015-1 R1 requires RC’s to communicate notifications that impact neighboring RC’s- EOP-002-4 R2 requires BA’s to communicate notifications that impact neighboring BA’s- TOP-001-2 R5 requires TOP’s to communicate notifications that impact neighboring TOP’sFinally, the draft IRO-014 R3 may introduce double jeopardy for non-compliance. The SDT should coordinate with the Project 2014-03 Revisions to TOP and IRO Standards Drafting Team IRO-014-3 requirement R3 and EOP-011-1

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	requirement R4. Those two requirements are very similar. It could argued that receiving a notification of an Emergency results in the RC identifying an actual emergency and then both EOP-011-1 and IRO-14-3 require the RC to notify other RC's. EOP-011-1 then goes further and requires the RC to notify other TOPs and BAs. The notification to other RCs is covered by these two Standards. This double jeopardy needs to be addressed. EOP SDT Response: The SDT appreciates your comments. The SDT reviewed the areas where the terms requesting BA was used and replaced it with "energy deficient BA" in the appropriate areas. The SDT removed the requirements in Requirements R1 and R2 for the coordination of plans with "impacted" entities. The SDT corrected the term Capacity and changed it to reflect the defined term "Capacity Emergency." In Requirement R4, the "as soon as practical" was removed. While the new IRO standards speak to the notifications, the SDT maintained the requirement since the standard is not an approved standard at this time.
American Electric Power	The drafting team's consideration of comments document states the following: "The EOP SDT discussed the many suggestions received for Requirement R1 and its detailed requirement parts. Based on comments received, the EOP SDT added details into the Requirement R1 Rationale that if any Requirement R1 Parts are not applicable, that the Transmission Operator should note "not applicable" in their plan." We find no mention of this in the R1 callout, though similar language is included in the callout for R2. Regardless, while we agree with such an allowance, we believe it should be included in the standard itself. Otherwise, an auditor could strictly adhere to the standard where it states "shall include the following elements." EOP SDT Response: The SDT appreciates your comments and has made this change.
FRCC	There is a potential for confusion due the SDTs use of the terms "Emergency Operation Plan". It appears that the SDTs intent is for readers to utilize the definitions in the Glossary of Terms for "Emergency" and "Operating Plan" to determine what is required by the Standard. The combining of these two definitions is confusing. If the SDT decides that the continued use of "Emergency Operation Plan" is needed, then a new definition should be developed to provide clarity around the intent and content of the plan. Therefore, the potential confusion of what an "Emergency

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	Operating Plan" actually entails could create difficulties when assessing compliance and is directly related to the 'measures' and the 'enforceability' of the requirements. The use of the term 'implement' in requirements R1 and R2 is confusing when compared to the language in Measures M1 and M2 and the RSAW. What does 'implement' actually mean in the context of the requirements? The requirements (R1 and R2) require an Emergency Operating Plan to be developed, maintained and implemented. Does this mean that the plan will be developed to include the required attributes identified in the requirement sub-bullets, will be maintained with periodic reviews to ensure the plan will appropriately address the specific emergency condition and be implemented. I believe implemented means that the plan is available for the System Operator's use, training has been completed and the Operators are proficient in the application of the plan. But when you read the Measure and the RSAW they are looking for evidence that the plan was actually activated in response to an emergency which is not part of R1 and R2. So if the plan is never used by the operator is that part of the audit over?R3 requires approval of the plan from the RC, but there is not documented criteria for the RC to assess approval and therefore is very difficult to assess compliance. Unless this is simply an exercise in documenting a 'yes' or 'no' EOP SDT Response: The SDT appreciates your comments and has separated the two defined terms. The term "implemented" is meant in the context of all the above statements made by the commentator. The SDT's intent is that either entity that has an Operating Plan to mitigate Emergencies will have it so that operators will be trained on it and use it if needed.
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Vectren appreciates the work of the standards drafting team, and generally supports the standard.
NV Energy	We commend the drafting team on their work to consolidated these multiple standards, streamlining the compliance requirements. Our negative vote on this draft stems from the concerns around the required coordination of manual and automatic load shedding as well as the consequences created with the language changes in the EEA Level 2 and 3 criteria.

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	EOP SDT Response: The SDT appreciates your comments and has made numerous modifications to the draft based on the comments received from the industry on the items the commenter has mentioned.

Additional Comments:

Austin Energy
Thomas Standifur

1. Based on comments from stakeholders, the EOP SDT has added the term “Operator-Controlled” preceding the language “manual Load shedding” in Parts of Requirements R1 and R2. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.

   ☒ Yes
   ☐ No
   Comments:

2. Based on comments from a majority of stakeholders, the EOP SDT removed Requirement 3 from EOP-011-1 draft 1 and has placed the requirement on the Balancing Authority and Transmission Operator to coordinate their Emergency Operating Plans with impacted Balancing Authorities and Transmission Operators. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.

   ☒ Yes
   ☐ No
   Comments:

3. The EOP SDT received several comments regarding Reliability Coordinator approval of Balancing Authority and Transmission Operator Emergency Operating Plans. The FERC directive in Paragraph 548 or Order 693 mandates that the Reliability Coordinator be included as an applicable entity; while plan approval by the Reliability Coordinator was

not a specific mandated intent, the EOP SDT believes that approval by the Reliability Coordinator reduces risk to reliability of the BES. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.

☐ Yes
☒ No
Comments: City of Austin dba Austin Energy (AE) does not believe Reliability Coordinators need to approve individual entity's Emergency Operating Plans. The effort presents an administrative burden on both the RC and the BA/TOP RC. AE believes the benefit of RC involvement could be in the concept of the RC coordination from the wide-area perspective. AE further believes RC coordination should not require RC approval. The RC could receive plans and be required to comment only if it identifies coordination issues. However, the SDT removed that concept (formerly R3) in this draft, and AE supports that decision. With the removal of the coordination role for the RC, AE remains unclear as to the intent of the RC approval. AE respectfully asks the SDT to remove this concept from the proposed versions of EOP-011-1 in consideration of Paragraph 81 criteria regarding administrative burden with no benefit to reliability. Further AE suggests considering the inclusion of the Reliability Coordinator in R4 and R5 as a response to the FERC directive in Paragraph 548 of Order 693.

EOP SDT Response: The SDT appreciates your comments and have removed the requirement that the RC approve an Operating Plan to mitigate Emergencies.

4. The EOP SDT has removed Requirement R5 from EOP-011-1 draft 1, as it is redundant with currently-enforceable TOP-001-1a. Do you agree with this revision? If not, please explain in the comment area below.

☒ Yes
☐ No
Comments: City of Austin dba Austin Energy (AE) supports the removal of R5 from EOP-011-1 draft 1 due to redundancy with TOP-001-1a. It seems, however, the SDT moved the concept into R1 Part 1.2.1 and R2 Part 2.2 of EOP-011-1 draft 2. AE disagrees with the addition of these parts to R1 and R2 for the same reasons (redundancy) as before.

EOP SDT Response: The SDT appreciates your comments. The SDT kept Requirement Part R1.2.1 and Requirement Part R2.2 because they are describing that the TOP and BA need a process in place so that a notification can be made to the RC. These requirements are not saying that a notification take place, but that a process needs to be included in the Operating Plan to mitigate Emergencies.

5. The EOP SDT has revised Attachment 1, removing “Operating Reserves” from EEA 2 and adding “Operating Reserves” into EEA 3. Do you agree with this change? If not, please explain in the comment area below.

☐ Yes
☐ No
Comments: [intentionally left blank]

6. Do you agree with the VRFs and VSLs in EOP-011-1? If not, please indicate which Requirement(s) and specifically what you disagree with, and provide suggestions for improvement.

☒ Yes
☐ No
Comments:

7. If you have any other comments on this Standard that you haven’t already mentioned above, please provide them here:

Comments: (1) City of Austin dba Austin Energy (AE) seeks clarity stating the Emergency Operating Plan required under R1 can be a single document or a combination of documents. This is similar to the allowance for a plan or set of plans in currently enforceable EOP-001-2.1b. (2) AE suggests the SDT remove the phrase “and generation” from R1, Part 1.2.3, as the TOP does not have control over generation outages. (3) AE suggests the SDT remove R1, Part 1.2.5, “Redispatch of generation request.” The TOP does not have the responsibility of generation dispatch nor does it necessarily have the visibility into the system to appropriately request generation redispatch.

EOP SDT Response: The SDT appreciates your comments. The SDT has modified these requirements based on industry comments, but has retained the intent that an entity must have a process in place to have these actions carried out, especially if they are not responsible for carrying out these actions.

END OF REPORT