Consideration of Comments

Project 2009-03 Emergency Operations

The Emergency Operations Drafting Team thanks all commenters who submitted comments on the proposed EOP-011-1 standard. These standards were posted for a 30-day public comment period from March 28, 2014 through April 28, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 40 sets of comments, including comments from approximately 131 different people from approximately 88 companies representing all 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

Index to Questions, Comments, and Responses

The Industry Segments are:

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				
No Additional Responses													
2.	Group	Joseph DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				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 Bos	Muscatine Power & Water	MRO	1, 3, 5, 6
14.	Scott Nickels	Rochester Public Utilities	MRO	4
15.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
17.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton	NERC Compliance Policy	NPCC	5, 6
2.	Randi Heise	NERC Compliance Policy	MRO	5
3.	Louis Slade	NERC Compliance Policy	RFC	5, 6
4.	Larry Nash	Electric Transmission Compliance	SERC	1, 3, 5, 6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Elting	Nebraska Public Power District	MRO	1, 3, 5
2.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
3.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
6.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
7.	Brandon Levander	Nebraska Public Power District	MRO	1, 3, 5
8.	Shannon Mickens	Southwest Power Pool	SPP	2
9.	James Nail	City of Independence, MO	SPP	3
10.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
11.	Don Schmit	Nebraska Public Power District	MRO	1, 3, 5
12.	Bruce Schutte	Nebraska Public Power District	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
5.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	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.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	1
8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	City of Green Cove Springs	FRCC	3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC		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	
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Matt Goldberg	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5

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

21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Sabouba	Hydro One Networks Inc,	NPCC	1
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5
25.	Ben Wu	Orange and Rockland Utilities	NPCC	1

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

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

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

No Additional Responses

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ray Phillips	AMEA	SERC	4
2.	Scott Brame	NCEMC	SERC	1, 3, 4, 5
3.	Connie Lowe	Dominion	SERC	1, 3, 6
4.	Terry Bilke	MISO	SERC	2
5.	Marsha Morgan	Southern	SERC	1, 5
6.	Richard Jackson	Alcoa Power Generating Inc.	SERC	5, 6, 7
7.	William Berry	OMU	SERC	3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5

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

2. John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
3. Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
4. Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

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	Regulated Marketing	RFC	5

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

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

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

Additional Member	Additional Organization	Region	Segment Selection
1. Ali Miremadi	CAISO	WECC	2
2. Cheryl Moseley	ERCOT	ERCOT	2
3. Ben Li	IESO	NPCC	2
4. Matthew Goldberg	ISONE	NPCC	2
5. Terry Bilke	MISO	RFC	2
6. Stephanie Monzon	PJM	RFC	2
7. Charles Yeung	SPP	SPP	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Mike O'Neil	Florida Power & Light	X									
No Additional Responses													
15.	Group	Sandra Shaffer	PacifiCorp						X				
No Additional Responses													
16.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1. Fran Halpin	Duty Scheduling	WECC	5										
2. Rich Ellison	Dispatch	WECC	1										
3. Jim Burns	Technical Operations	WECC	1										
17.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
18.	Individual	Ronnie C. Hoeinghaus	City of Garland			X							
19.	Individual	Ayesha Sabouba	Hydro One	X		X							
20.	Individual	Dave Willis	Idaho Power Company	X									
21.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
22.	Individual	Michael Falvo	Independent Electricity System Operator		X								
23.	Individual	John Seelke	Public Service Enterprise Group	X		X	X	X					
24.	Individual	Michelle D'Atnuono	Ingleside Cogeneration LP					X					
25.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				
26.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
27.	Individual	Lorraine Landers	Consumers Energy Company			X	X	X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
29.	Individual	Anthony Jablonski	ReliabilityFirst										X
30.	Individual	John Brockhan	CenterPoint Energy	X									
31.	Individual	Matt Beilfuss	Wisconsin Electric			X	X	X					
32.	Individual	David Thorne	Pepco Holding Inc.	X		X							
33.	Individual	Scott Langston	City of Tallahassee	X									
34.	Individual	Bill Fowler	City of Tallahassee, TAL			X							
35.	Individual	Karen Webb	City of Tallahassee					X					
36.	Individual	William Temple	Northeast Utilities	X									
37.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
38.	Individual	Joshua Smith	Oncor Electric Delivery Company LLC	X									
39.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Lisa Martin	City of Austin dba Austin Energy	X		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"
Tennessee Valley Authority	Agree	SERC OC Review Group

1. **Based on the EOP FYRT recommendations, the EOP SDT has combined three standards into the proposed EOP-011-1, Emergency Operations. The original standards are EOP-001-2.1b (Emergency Operations Planning), EOP-002-3.1 (Capacity and Energy Emergencies) and EOP-003-2 (Load Shedding Plans). Do you support the consolidation of these standards? If not, please provide specific recommendations for the EOP SDT in your comments.**

Summary Consideration: The EOP SDT appreciates the support received for Project 2009-03 and in the merging of the three original standards EOP-001-2.1b (Emergency Operations Planning), EOP-002-3.1 (Capacity and Energy Emergencies) and EOP-003-2 (Load Shedding Plans) into one standard, EOP-011-1 Emergency Operations, to provide clarity regarding the critical requirements and to promote coordination and communication across functional entities.

Organization	Yes or No	Question 1 Comment
SPP Standards Review Group	Yes	The work of the SDT in consolidating these standards on emergency operations and clarifying the different requirements between the BA and TOP is appreciated and commendable.
SERC OC Review Group	Yes	The OC Review Group supports the EOP SDT action to combine three standards into the proposed EOP-011-1. Further, the OC Review Group thanks the EOP SDT for their efforts in developing the proposed EOP-011-1.
ACES Standards Collaborators	Yes	We support the consolidation of the three standards, but we question why the drafting team chose to label the new standard as EOP-011-1. Why wouldn't the revised standard be labeled as EOP-001-3? This would be consistent with other drafting team projects and would be less confusing to industry members that do not follow the standards development process that closely. Considering this EOP standard is going to consolidate the key emergency operations standards, it only makes sense to call it EOP-001.

Organization	Yes or No	Question 1 Comment
Idaho Power Company	Yes	Consolidation of the three standards is good, the less redundant standards the better.
Xcel Energy	Yes	Xcel Energy supports moving to a single standard as it will leave less room for potential conflicts between multiple documents.
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP (ICLP) supports the project team's efforts to clearly separate compliance responsibilities by entity. In our view, the mixing of TOP and BA requirements in the existing standards has only served to introduce confusion - leading the possibility open that both or neither entity will take these actions. This leads to a reliability gap that we believe EOP-011-1 successfully addresses.
Consumers Energy Company	Yes	Agree that the merging of the three standards will provide clarity of the critical requirements and promoting coordination and communication across functional entities
American Transmission Company, LLC	Yes	ATC supports the consolidation of the noted EOP standards into the proposed EOP-011-1. However, ATC recommends that Parts R1.2.1 - R1.2.6 and R1.3 of Requirement R1 be rewritten as detailed in the response to Question 2.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 1 Comment
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	
DTE Electric	Yes	
ISO/RTO Standards Review Committee	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
American Electric Power	Yes	
City of Garland	Yes	
Hydro One	Yes	
Independent Electricity System Operator	Yes	
Public Service Enterprise Group	Yes	

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Yes	
Tacoma Power	Yes	
ReliabilityFirst	Yes	
CenterPoint Energy	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Oncor Electric Delivery Company LLC	Yes	
City of Austin dba Austin Energy	Yes	

2. **The EOP SDT has developed proposed Requirement R1 to specify the minimum set of elements required for the Transmission Operator to include in their Emergency Operating Plan. Do you agree with the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.**

Summary Consideration: 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. There were also updates, additions and deletions made to the requirement parts to lend more clarity and to streamline the requirement and requirement parts, as the industry comments had suggested.

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Forum	No	Since R1.1 is part of the Operating Plan, an entity does not need a “Definition of” roles and responsibilities. Recommend to remove “Definition of” in R1.1. R1.2, Since an Operating Plan is defined as a procedure or process, recommend deleting “Procedures, processes or” from R1.2. R1.2.2 should contain the cancelling or recalling of generation outages too. R1.3, recommend to add “topology or System configuration” at the end of R1.3. This further defines that a major change will need to be accomplished in order to review your Emergency Operating Plan. Note that this Requirement (Federal Law) gives the entity a bright line to when a change has to me made. The entity can make any change at any time regardless of this bright line criteria.
Dominion	No	Part 1.2.6 says ‘Strategies to be used to mitigate reliability impacts of extreme weather conditions.’ Part 2.2.9 says ‘Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan.’ Dominion suggests revising Part 1.2.6 to read “Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan.” which has the same caveat for coverage by other elements of the plan as Part 2.2.9.

Organization	Yes or No	Question 2 Comment
SPP Standards Review Group	No	We agree with the intent of the SDT to create a separate requirement for Transmission Operators to have an Emergency Operating Plan. Unfortunately, the requirement actually combines three requirements (development, maintenance and implementation) into a single requirement. We recommend splitting each of these into separate requirements. Additionally, the Time Horizon for development and maintenance of the Emergency Operating Plan is different than that for implementation. It may be more appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies on its Transmission System within R5. Also, the Violation Risk Factors for development and maintenance of the plan should be “Medium”, while the Violation Risk Factor for implementation should be “High”. Corresponding changes to M1 would need to be made to reflect these proposals. The measurement for implementation is also troubling as registered entities may be in the position of having to prove a negative if they do not have an Emergency during an audit period. Additionally, we request clarification on the intent of the term ‘implement’ in R1. Does this mean simply disseminating the Plan throughout your organization including providing it to your operators? Or does this mean activating your Plan when an Emergency occurs? If it’s the former, then it fits this requirement and we would propose the SDT use ‘disseminate’ or ‘issue’ for the term. However, if it is the latter, then it doesn’t belong in this requirement but perhaps in R5. It seems that the intent could be the latter since the SDT used implement again in Part 1.1 in conjunction with activate. The Emergency Operating Plan, specified in R1, should include the requirement to notify the TOP’s RC of its current and projected System conditions. R5 would then simply require implementation of the plan. (See our comment in Question 10 below.)Part 1.3. is not clear. An emergency plan that includes procedures, processes and strategies, may not need to be revised for every change to the TOP’s System. The requirement does not include any periodic review. Is the intent of the SDT that the process include some periodic review or is that entirely up to the TOP? As currently stated, the scope is entirely too broad. In the 2nd line of M1, insert a space between ‘R1’ and ‘that’.

Organization	Yes or No	Question 2 Comment
Florida Municipal Power Agency	No	Does the RC really need to approve, or should it be a coordination requirement? If so, then there ought to be a description of what types of changes ought to require approval and what changes do not, e.g., do minor changes such as phone number updates need to be approved?
Duke Energy	No	(1)Duke Energy questions the need to require a BA/TOP have its Emergency Operating Plan approved by a Reliability Coordinator. On its face, there doesn't appear to be a clear Reliability-based need to have an BA/TOP's individual Emergency Operating Plan approved, and respectfully requests that the SDT provide more clarity on the technical justification for requiring RC-approval. If the Reliability-based need is not readily attainable, the standard/requirement should be viewed as purely administrative in nature, and be treated as unduly burdensome. (2)R1.2.4:As written, R1.2.4 is not clear on what is meant by "Processes for redispatch of generation". Is it the intent of the SDT to have the TOP work with the other Functions involved? If this is the intent of the SDT, it should be explicitly stated that a TOP must work with other Functions involved for a process on the redispatch of generation. "Process for requesting the redispatch of generation."(3)The EOP SDT has used the term "Emergency Operating Plan" in R1. as a NERC defined term by capitalizing. Duke Energy believes the intent of this term is to combine the definitions of "Emergency" and "Operating Plan" from the NERC Glossary, but recommends the SDT to take this under consideration. The use of Operating Plan in the requirement is the correct and consistent approach since it is our understanding that the NERC SDT's have been guided to use defined terms and not use terms such as plan, process, and procedure to eliminate any ambiguity. Because of this approach, Duke Energy questions the use of Plans, Processes, and Strategies in R1.2. and at the beginning of each sub-requirement to R1.2. with the exception of R1.2.5., which has been written differently. The NERC term Operating Plan is defined as, "A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units,

Organization	Yes or No	Question 2 Comment
		Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan." (4)Because the definition of Operating Plan includes "Operating Procedures" and "Operating Processes" (both are NERC defined terms), we recommend the use of these terms in the sub-requirements to be consistent with the direction of other standards that are currently effective or under development. The use of the term "Strategies" will also need to be considered by the SDT to either be replaced with one of the NERC defined terms or propose a new term "Operating Strategies" for comment during the development of Reliability Standard EOP-011-1. (5)R1.2.6:Duke Energy feels as though this requirement is overly broad, and could possibly be viewed as a candidate for Paragraph 81 criteria. Strategies to mitigate reliability impacts of extreme weather are not "one-size fits all". Not all regions experience the same extreme weather conditions, which could make this requirement difficult to audit against. Duke Energy suggests placing objective and clearly quantifiable measures and VRF/VSL(s) in place to assist a TOP in ascertaining the responsibilities expected for audit purposes." Identify strategies used to mitigate adverse reliability impacts of extreme weather events."
SERC OC Review Group	No	The OC Review Group is concerned with the phrase "At a minimum" as it is possible that certain elements may not be applicable to a certain TOP. It is recommended that the term "applicable" be utilized. Current R1 language: R1. 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, the Emergency Operating Plan shall include the following elements: Proposed R1 language: R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. The Emergency Operating Plan shall include the applicable elements when developing an Emergency Operating Plan:
ACES Standards Collaborators	No	(1) We see several issues with these proposed requirements. First, the term "Emergency Operations Plan" is not a defined term. This should either be lowercase

Organization	Yes or No	Question 2 Comment
		or the SDT should propose to add it to the NERC glossary. (2) The glossary term "Energy Emergency" is not the same as "Energy Emergency Alert." The supplemental document showing each standard that uses the term has incorrectly identified an EEA. We recommend reviewing the standards again to verify that the revision to the glossary term does not impact standards that use the word "emergency" in the requirements. (3) The RC approval process is an administrative action that does not support reliability. The approval process should be completed internally. This process is a burden for RCs and registered entities, especially smaller entities that may not have an impact on the reliability of the RC Area. Having an internal approval that aligns with the RC emergency plans would satisfy the intent of the requirement, but would also limit the administrative functions that relate to getting an approval from the RC. The requirement could state that the plans must align with RC emergency plans, which are posted and available to all registered entities in the RC Area. Verifying this information is much simpler if done internally, instead of burdening RC staff with approving each member's plan. As an alternative, the RC could be required to simply review the plans for conflicts. (4) Does the RC need to approve every change to the plan? Within what timeframe? The standard is not clear regarding the process for getting RC approval and secondary approvals for subsequent changes. Again, this is administrative in nature. (5) Requirement R1, part 1.3, meets Paragraph 81 criteria because it is completely administrative. There is no reason that a standard needs to require the details of a revision process. The requirement already has the word "maintain" in relation to the plan, which implies that updates will be made when necessary. This should be removed.
Florida Power & Light	No	This new requirement is too prescriptive, specifically requirement 1.2 where it defines minimum requirements a BA should include in the Emergency Operating Plan. Some of these requirements may not apply to all BAs.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	AEP believes R1.2.4 (Processes for redispatch of generation) is applicable to the Balancing Authority, and *not* the Transmission Operator (who does not redispatch generation).
Xcel Energy	No	R1 and R2 language is strict in that an entity's EOP "shall include" elements defined in R1.1 to R1.3 and R2.1 to R2.3 respectively. What will happen in a situation where one of those elements does not apply to an entity? This standard is implying that all the elements identified in R1.1 to R1.3 and R2.1 to R2.3 must be included in the EOP whether they are applicable or not. The current EOP-001 R4 allows for in its Attachment 1 to be omitted if they are not applicable ("shall include the applicable elements"). We feel like the new EOP-011 standard should include similar language to allow for this flexibility. Could the Standard Drafting Team respond why the language in EOP-011 R1 and R2 was written to be more restrictive than the current EOP-001 R4 and whether items in R1.1 to R1.3 or R2.1 to R2.3 could be omitted from an EOP if found to be not applicable to an entity? Additionally, the word "develop" should be removed from the requirement. Every entity should have a plan today. It should be maintained and implemented. IF an entity does not have a plan, it will have to develop one to have one to implement. The requirement does not need to address this issue.
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration: 1. Requirement R1 and R2 - 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

Organization	Yes or No	Question 2 Comment
		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."
CenterPoint Energy	No	CenterPoint Energy has concerns with Requirement R1 as drafted and offers the following recommendations. One, CenterPoint Energy is concerned that, as drafted, Requirement R1 restricts TOPs to one single Emergency Operating Plan. The Company believes TOPs should be able to utilize multiple plans to address R1, as long as the plans in aggregate include all the required elements. Two, CenterPoint Energy does not support requiring the RC to approve the TOP's Emergency Operating Plans. Paragraph 548 of Order 693 only directed that the RC be added as an applicable entity, not for the RC to assume approval responsibility. Thus, to incorporate suggestions 1 and 2, the proposed Requirement R1 should be revised to state: "Each Transmission Operator shall develop, maintain, and implement one or more Emergency Operating Plans to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plans shall include the following elements:". Three, CenterPoint Energy believes R1 Part 1.1 is unnecessary. TOP-001-1a Requirement R1 states that Transmission Operators 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 definition of roles and responsibilities are unnecessary. CenterPoint Energy recommends R1 Part 1.1 be deleted. Four, CenterPoint Energy believes R1 Part 1.2.1 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.

Organization	Yes or No	Question 2 Comment
		CenterPoint Energy believes Part 1.2.1 is unnecessary and should be deleted from the proposed EOP-011-1. Five, CenterPoint Energy believes the “extreme weather conditions” referenced in R1 Part 1.2.6 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 1.2.6 is unnecessary and should be deleted. If, however, the SDT insists on retaining such a requirement, CenterPoint Energy recommends Part 1.2.6 be revised to state: “Strategies to be used to mitigate reliability impacts of extreme weather conditions defined by the Transmission Operator.”
Pepco Holding Inc.	No	Why not include many of the other elements included in R2 for Transmision Emergencies?
City of Tallahassee	No	The language from R1.2.6 referring to the potential impacts of extreme weather is difficult to quantify. Due to the lack of specificity, TAL would create “high level strategies” similar to those created for restoration from black start resources. Also, requiring the RC to approve the plan places an administrative burden on both the entity and the RC.
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) requests the SDT remove the requirement for the RC to approve each TOP Emergency Operating Plan. Absent technical justification, AE believes the approval process is unnecessary and administratively burdensome. The FERC directive in Order 693, Paragraph 548 requires the SDT to include the RC in the applicability of the standard, not to make the RC approve all Emergency Operating Plans. If the SDT believes the approval is necessary and intends the approval to be limited to the RC coordination effort required in R3, AE requests the SDT include a reference to R3 in R1.

Organization	Yes or No	Question 2 Comment
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 requests clarification on the term “Emergency Operating Plan.” Did the SDT intend for “Emergency Operating Plan” to be a new term or is the meaning associated with each term separately: “Emergency” and “Operating Plan.”This standard reemphasizes a widespread concern that the definition of “Emergency” in the NERC Glossary is too broad to make it possible to create this document. We feel that an Emergency Operating Plan should exist for significant operating conditions and not the full spectrum of conditions that the current Emergency term encompasses.
Idaho Power Company	Yes	The minimum set of requirements is fine. I question that the plan needs to be approved by the Reliability Coordinator. If during an audit a plan is found to be deficient by the auditors but has been approved by the Reliability Coordinator where does the liability fall, With the Transmission Operator or the RC as the approver of the plan?1.2.4. Redispatch of Generation- seems more like a BA function than a TOP function.
American Transmission Company, LLC	Yes	ATC agrees with the wording of the proposed Requirement R1. However, ATC recommends that Parts R1.2.1 - R1.2.6 of Requirement R1 be rewritten as: R1.2.1 - Controlling voltage;R1.2.2 - Cancelling or recalling Transmission outages;R1.2.3 - System reconfiguration;R1.2.4 - Redispatch of generation; R1.2.5 - Manual load shedding designed to minimize the reliance on automatic load shedding;R1.2.6 - Mitigation of reliability impacts of extreme weather conditions; The changes to Parts R1.2.1 - R1.2.6 eliminate references to documentation that is previously specified in Part 1.2 of Requirement R1. The revision of Part 1.2.5 also provides clarification regarding the relationship between manual and automatic load shedding. In addition, ATC recommends that Part R1.3 be rewritten as “A process for reviewing its Emergency Operating Plan on an annual basis to evaluate the impact of changes to its System and revising the Emergency Operating Plan accordingly.” This revision

Organization	Yes or No	Question 2 Comment
		specifies an “annual” time requirement to the Emergency Operating Plan review and revision process.
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	
DTE Electric	Yes	
ISO/RTO Standards Review Committee	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
City of Garland	Yes	
Hydro One	Yes	
Independent Electricity System Operator	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 2 Comment
Tacoma Power	Yes	
Consumers Energy Company	Yes	
Wisconsin Electric	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Oncor Electric Delivery Company LLC	Yes	

3. The EOP SDT has developed proposed Requirement R1, Part 1.2.5 as a process to include manual Load shedding plan coordination. Do you agree that Requirement 1, Part 1.2.5 clearly defines required performance? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: In Requirement R1, Part 1.2.6., the EOP SDT has added the term “Operator-controlled” preceding the language “manual Load shedding,” as it was in the currently-enforced standard, EOP-003-2 Requirement R8. The EOP SDT also agrees that the intent of UFLS is meant as all automatic Load shedding, including UVLS, if applicable; but to still largely maintain separate “plans” for manual and automatic Load shedding. It is the EOP SDT’s intention that entities would strive to maintain an operator-controlled manual Load shedding plan that is largely separate and distinct from their automatic Load shed plans. The EOP SDT also understands that when, for example, localized Load shedding is needed, that it may need to include feeders that are part of any automatic Load shed system.

Conversely, for Capacity Emergencies, if operator-controlled Load shedding is needed, it is desirable to avoid feeders with automatic Load shedding, such that automatic Load shedding functionality is maintained.

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Forum	No	We believe that the "automatic Load shedding" is either UFLS or UVLS (and maybe an SPS/RAS). It is very hard to (and impossible) "coordinate" an automatic system with a manual system. Since R1.2.5 is an element of the Emergency Operating Plan, recommend R1.2.5 to read: Manual Load shedding plan(s) incorporated to minimize the use of automatic Load shedding;". This will allow the entity to have a preconceived (pre-planned) process for when the risk is higher that an automatic Load shedding may occur
Dominion	No	Dominion is concerned that this could be read as requiring manual (human at station) load shed as opposed to automatic (SCADA) when we believe the intent is to coordinate so as to avoid overlap with UFLS and UVLS programs. We suggest 1.2.5 read as 'Operator controlled manual Load shedding plan coordinated to minimize the use of UFLS and UVLS automatic Load shedding.' In which operator controlled manual load shedding was used in EOP-003-2.
SPP Standards Review Group	No	The phrase "coordinated to minimize the use of automatic Load shedding" in Requirement 1, Part 1.2.5 is not clear. Is the intent to coordinate the manual Load shedding plan with those locations that have automatic Load shedding installed so as not to duplicate the same Load in both manual and automatic plans? Or is the intent to develop a manual Load shedding plan that will be enacted quickly enough so that automatic Load shedding is minimized? If it is the former, we suggest revised language for Part 1.2.5.: "Manual Load shedding plan coordinated to minimize the use of locations with automatic Load shedding;". We may even go further to propose deleting the phrase "to minimize the use of automatic load shedding" entirely as this seems to be a bit of editorializing. If it is the latter, then the reason for having a

Organization	Yes or No	Question 3 Comment
		manual Load shedding plan is immaterial in the standard. It definitely needs to be in your Emergency Operating Plan, just not in the standard.
Florida Municipal Power Agency	No	1.2.5 ought to be specific to UVLS and should not apply to UFLS. A TOP has no role in manual load shedding to address a capacity / energy emergency to coordinate with UFLS. It is unrealistic to expect load shedding for purposes of solving local transmission problems to retain enough load in the local area to then be able to participate fully in the UFLS program, e.g., it may be necessary to shed all of the load at a particular substation to solve an overload due to multiple contingencies on the transmission system, which will mean that the UFLS relays on the feeders at that substation will not participate in a subsequent UFLS event. Missing those limited number of UFLS relays will not have a meaningful effect on the effectiveness on a UFLS program which is more regional in nature.
Northeast Power Coordinating Council	No	We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 falls short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest expanding this part as follows:1.2.5 Manual Load shedding plan coordinated with automatic loading programs to minimize the use of automatic Load shedding, and also coordinated with the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding.
Duke Energy	No	R1.2.5:Duke Energy requests clarification on the intent of R1.2.5. Is it the intent of the SDT for a TOP to coordinate a Manual Load Shedding Plan to reduce the double counting of load used in an Automatic Load Shedding Scheme, or to reduce the overall dependency on the use of Automatic Load Shedding? A re-wording is needed to clearly state the purpose of this requirement. Also, we request further explanation as to what the SDT means by using the term “coordination” in the requirement. Further explanation as to what the SDT means by using “coordination” could provide some clarity on how a TOP can minimize the use of Automatic Load Shedding in favor of a Manual Load Shedding Plan. Duke Energy is of the opinion that the term

Organization	Yes or No	Question 3 Comment
		“minimize” as used in the requirement is difficult to quantify, and is not a term equated with Auditability.
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 does not agree that R1, Part 1.2.5 clearly defines required performance. Southern recommends that the SDT modify the rationale included in the standard or the technical background and rationale document to clearly explain the intent of the requirement.
SERC OC Review Group	No	The OC Review Group recommends that adding “Operator controlled” further clarifies R1, Part 1.2.5R1, Part 1.2.5. Current language: Manual Load shedding plan coordinated to minimize the use of automatic Load shedding;R1, Part 1.2.5 Proposed language: Operator controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding;
ACES Standards Collaborators	No	(1) It is not clear what parties are supposed to coordinate their plans. Coordination is an ambiguous term that could be interpreted in multiple ways. The measure does not provide any additional guidance on what is expected for coordination and the drafting team did not provide compliance guidance or an RSAW with this draft. Are TOPs supposed to coordinate with other TOPs? Other BAs? Or is the standard proposing that the RC approval process is evidence of coordination? This is not clear and needs to be revised. The bottom line is that coordination is a vague requirement that needs to be further refined to clearly spell out what is required for coordination.

Organization	Yes or No	Question 3 Comment
Florida Power & Light	No	Requirement not clear. Is this requirement intended to use the manual load shed to prevent automatic load shed; or is it to ensure that the same resource is not used for manual and automatic load shed.
PacifiCorp	No	R1, Part 1.2.5 does not clearly define required performance. In the proposed requirement, the language ‘coordinated to minimize the use of automatic Load shedding’ does not provide sufficient guidance on the intended load shed policy. The Drafting Team should develop language which provides more specific guidance on how manual Load shedding should be coordinated, and provide a more specific performance measure than ‘minimize the use’ of automatic Load shedding. With respect to the latter, the Drafting Team may want to specifically reference minimizing dependence on under voltage and under frequency Load shedding plans if that is the intention.
American Electric Power	No	AEP does not endorse the current draft of EOP-011-1 R1.2.5 as it is too prescriptive. There could be situations where it is desirable to use UVLS instead of manual load shed since an operator could not shed load fast enough. As a concrete example, consider a situation where there are two major 138kV feeds into an area. If one feed is out of service, and the other were to trip, there would be severe voltage depression with the only the subtransmission support unless UVLS is quickly utilized. It is not clear what the SDT intention is with 1.2.5 as it relates to minimizing risk to the Bulk Electric System.
Idaho Power Company	No	No. Automatic load shedding would include under-voltage and under-frequency load shedding which would happen as the result of relay operation. An Operator may not have adequate time to manually shed load to prevent automatic load shedding. The automatic schemes are in place to protect the BES as they should be. I think the requirement should not focus on coordination as much as having a manual load shedding plan.As part of 1.2, it should say "Processes for manual load shedding."

Organization	Yes or No	Question 3 Comment
Xcel Energy	No	There is no defined performance because of the use of the word “minimize”. Does this mean any use of automatic load shedding violates the standard? If so, entities should remove any automatic load shedding capability so they do not violate the standard. However, that will put the interconnection at greater risk, which is not the goal of the standards. As written, there is no clear measurement process. It would have to be argued on a case by case basis and an auditor/regulator can argue any automatic load shedding violates the standard. This is a detail that can not be properly addressed in a standard as the specifics will vary with each entity.
Public Service Enterprise Group	No	The requirement for a coordinated manual Load shedding plan is a good one. However, the TOP should coordinate its plan with its LSEs, DPs, and their respective BAs. BAs should be added to the TOP coordination because a manual Load shedding plan is also required in R2 for BAs. The two entities (TOP and BA) should coordinate their manual Load shedding plans among themselves before submitting such plans to their RC for approval. Part 1.2.5 should therefore be modified as follows: “Manual Load shedding plan coordinated [ADD: among its Load Serving Entities and Distribution Providers and their respective Balancing Authority(ies) ....]”
Manitoba Hydro	No	(1) R1.2.5 contains a requirement that manual Load shedding be coordinated, but does not specify with whom the Load shedding should be coordinated. The coordinating entities should be specified.
Tacoma Power	No	Tacoma Power is unsure if the intent is: a) for the System Operator to minimize manually shedding facilities that have automatic load shedding equipment installed in lieu of facilities that do not, -OR- b) to utilize manual load shedding (preemptively) to attempt to forestall automated load shedding from occurring.
American Transmission Company, LLC	No	ATC agrees with the wording of the proposed Requirement R1, but recommends that Part 1.2.5 be modified to “Manual load shedding designed to minimize the reliance

Organization	Yes or No	Question 3 Comment
		on automatic load shedding;" This revision provides clarification regarding the relationship between manual and automatic load shedding.
Wisconsin Electric	No	It is not clear what or with whom coordination is required. The proposed standard "Rationale for R1" section indicates that TOP and BA load shedding "sometimes" needs to be coordinated. However, neither R1 (TOP requirement) nor R2 (BA requirement) explicitly require coordination between the two.
City of Tallahassee	No	TAL is confused by R1.2.5. Is the intent not to overlap manual and automatic (UFLS) load shed tools (i.e. feeder circuits) or is the intent to require manual load shedding prior to activation of automatic load shedding? The verbiage does not specify who must be part of the coordination effort.
Lincoln Electric System	No	Recommend additional clarification be added to Part 1.2.5 to specify whether the loads used by the operators in a Manual Load Shedding plan are either used last, or not at all, in comparison to the loads that are already defined in any automatic under-frequency or automatic under-voltage load shed plans.
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) requests clarification as to whether R1, Part 1.2.5 intends to minimize the overlap between manual Load shed feeders and automatic Load shed (i.e., UFLS and UVLS) feeders. If so, what does "minimize" mean?
ISO/RTO Standards Review Committee	Yes	We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 appears to fall a bit short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest expanding this part, and add a new part as follows:1.2.5 Manual Load shedding plan coordinated with automatic load shedding programs to minimize the use of automatic Load shedding;1.2.6 Manual Load shedding plan coordinated with the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding;

Organization	Yes or No	Question 3 Comment
Independent Electricity System Operator	Yes	We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 appears to fall a bit short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest to expand this part as follows:1.2.5 Manual Load shedding plan coordinated with automatic loading programs to minimize the use of automatic Load shedding, and the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding.
Northeast Utilities	Yes	We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 appears to fall a bit short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest expanding this part as follows:1.2.5 Manual Load shedding plan coordinated with automatic loading programs to minimize the use of automatic Load shedding, and also coordinated with the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding.
Arizona Public Service Company	Yes	
DTE Electric	Yes	
Bonneville Power Administration	Yes	
City of Garland	Yes	
Hydro One	Yes	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 3 Comment
Pepco Holding Inc.	Yes	
Oncor Electric Delivery Company LLC	Yes	

4. **The EOP SDT has developed proposed EOP-011-1, Requirement R1, Part 1.2.5 without a specific time measure. The currently-enforceable EOP-003-2, Requirement R8 states, "… timeframe adequate for responding to the emergency." Do you support Requirement R1, Part 1.2.5 without a time measure? If not, please provide specific suggestions for improvement, including alternate language**

Summary Consideration: The EOP SDT agrees that the time frame may vary by the request of the Reliability Coordinator or Transmission Operator as a directive. If a directive cannot be performed in the time frame requested, the process (per TOP-001-1, IRO-001 [as well as other standards]) is to report this information back to the Reliability Coordinator/Transmission Operator so that further actions can be taken to mitigate the event. The rationale for Requirement R2 states that an Emergency plan may sometimes require coordination between the Balancing Authority and the Transmission Operator. The EOP SDT held discussion to emphasize the importance of coordination between the Balancing Authority and Transmission Operator in any type of event pertaining to manual Load shed and in addressing how a directive should be handled, regardless of the content of the directive.

Organization	Yes or No	Question 4 Comment
SPP Standards Review Group	No	One of the issues identified in previous events has been that some entities have manual Load shedding plans that require dispatching personnel to dispersed locations to implement the plan. The standard should include a requirement that manual Load Shedding be able to be implemented in time to mitigate the Emergency. We suggest the requirement include that the Manual Load shedding plan be capable of being implemented by an operator remotely. This addresses the issue of not being able to respond quickly to a given situation while at the same time eliminating the ambiguity of maintaining the existing language in EOP-003-2, R8.
PacifiCorp	No	PacifiCorp supports use of language similar to EOP-003-2 R8 and the language "... timeframe adequate for responding to the emergency." PacifiCorp annually updates detailed analyses which produce block load shed plans and instructions. Operator training, combined with block load shed plans and instructions, ensures operators are

Organization	Yes or No	Question 4 Comment
		capable of implementing load shedding in a timeframe adequate for responding to an emergency.
Tacoma Power	No	The current EOP-003-2 R8 language “timeframe adequate for responding to the emergency” should remain. Load shedding plans that are not viable (i.e. the System Operator has no hope of actually executing the plan quickly enough to mitigate the emergency) are useless. Tacoma Power fears that without this measurement, plans that are not actually useful may be created.
Northeast Power Coordinating Council	Yes	There are other standards with requirements in place to mitigate emergency conditions (e.g. IROL violations) in specific time frames. Imposing another time frame creates the potential for having multiple violations for the same infraction.We agree with not specifying a time frame since the time required to implement and complete manual load shedding will depend on a number of conditions, such as: the completion of the automatic load shedding and its effects on mitigation, the time needed for manual load shedding to be completed from the time of initiation, other available actions that may be taken prior to shedding load, etc. The reliability driver is to arrest/mitigate Emergency as soon as possible. System Operators will have this reliability driver in mind when faced with an Emergency, and are the best judge to determine when should manual loading be initiated and completed.
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	Other standards adequately cover the time frame requirements.

Organization	Yes or No	Question 4 Comment
Generation and Energy Marketing		
ACES Standards Collaborators	Yes	We support manual firm load shedding without a specific time measure. However, we are concerned the compliance monitoring approaches may create a de facto time requirement. We would like to see guidance or an RSAW to state how this will be evaluated.
ISO/RTO Standards Review Committee	Yes	We agree with not specifying a time frame since the time required to implement and complete manual load shedding will depend on a number of conditions, such as: the completion of the automatic load shedding and its effects on mitigation, the time needed for manual load shedding to be completed from the time of initiation, other available actions that may be taken prior to shedding load, etc. The reliability driver is to arrest/mitigate an Emergency as soon as possible. System Operators will have this reliability driver in mind when faced with an Emergency, and are the best judges of when manual load shedding should be initiated and completed.
Xcel Energy	Yes	The time frame is determined by the emergency. The current language is impossible to fairly enforce. Therefore, it should be removed. We support the drafting team's position on this issue.
Independent Electricity System Operator	Yes	We agree with not specifying a time frame since the time required to implement and complete manual load shedding will depend on a number of conditions, such as: the completion of the automatic load shedding and its effects on mitigation, the time needed for manual load shedding to be completed from the time of initiation, other available actions that may be taken prior to shedding load, etc. The reliability driver is to arrest/mitigate Emergency as soon as possible. System Operators will have this reliability driver in mind when faced with an Emergency, and are the best judge to determine when should manual loading be initiated and completed.
Pepco Holding Inc.	Yes	Don't need to duplicate the same requirement in different Standards.

Organization	Yes or No	Question 4 Comment
American Transmission Company, LLC	Yes	ATC supports Requirement R1, Part 1.2.5 without a time measure because time measures are defined in the applicable TOP standards. However, ATC recommends Part 1.2.5 be modified to “Manual load shedding designed to minimize the reliance on automatic load shedding;” This revision provides clarification regarding the relationship between manual and automatic load shedding.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
Bonneville Power Administration	Yes	
American Electric Power	Yes	
City of Garland	Yes	

Organization	Yes or No	Question 4 Comment
Hydro One	Yes	
Idaho Power Company	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
CenterPoint Energy	Yes	
Wisconsin Electric	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Oncor Electric Delivery Company LLC	Yes	
City of Austin dba Austin Energy	Yes	

5. The EOP SDT developed Requirement R2 to specify the minimum set of elements required for the Balancing Authority to include in their Emergency Operating Plan. Do you agree with the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: The EOP SDT discussed the many suggestions received for Requirement R2 and its detailed requirement parts. Based on comments received, the EOP SDT added details into the Requirement R2 rationale that if any Requirement R2 Parts are not applicable, that the Balancing Authority should note "not applicable" in their plan. There were also updates, additions and deletions made to the requirement parts to lend more clarity and to streamline the requirement and requirement parts, as the industry comments had suggested.

Organization	Yes or No	Question 5 Comment
MRO NERC Standards Review Forum	No	Since R2.1 is part of the Operating Plan, an entity does not need a "Definition of" roles and responsibilities. Recommend to remove "Definition of" in R2.1. R2.2, Since an Operating Plan is defined as a procedure or process, recommend deleting "Procedures, processes or" from R2.2. R2.3, recommend to add "topology or System configuration" at the end of R2.3. This further defines that a major change will need to be accomplished in order to review your Emergency Operating Plan. Note that this Requirement (Federal Law) gives the entity a bright line to when a change has to me made. The entity can make any change at any time regardless of this bright line criteria.
Dominion	No	The last sentence in R2 Dominion suggests adding "the following elements:" for consistency with R1.What is meant by Governmental programs in 2.2.4, this needs more description or some examples? Are governmental programs exclusive of 2.2.2, 2.2.3 and 2.2.7 and if so, why are they

Organization	Yes or No	Question 5 Comment
		exclusive? EOP-001-2.1b Attachment 1 says "12. Requests of government - Requests to appropriate government agencies to implement programs to achieve necessary energy reductions." This seems to be a type of energy reduction which is covered in 2.2.7, therefore Dominion suggests removing 2.2.4.
SPP Standards Review Group	No	We agree with the intent of the SDT to create a separate requirement for Balancing Authorities to have an Emergency Operating Plan. Unfortunately, the requirement actually combines three requirements (development, maintenance and implementation) into a single requirement. We recommend splitting each of these into separate requirements. Additionally, the Time Horizon for development and maintenance of the Emergency Operating Plan is different than that for implementation. It may be more appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies within its Balancing Authority Area within R6. Also, the Violation Risk Factors for development and maintenance of the plan should be "Medium", while the Violation Risk Factor for implementation should be "High". Corresponding changes to M2 would need to be made to reflect these proposals. The measurement for implementation is also troubling as registered entities may be in the position of having to prove a negative if they do not have an Emergency during an audit period. Additionally, we request clarification on the intent of the term 'implement' in R2. Does this mean simply disseminating the Plan throughout your organization including providing it to your operators? Or does this mean activating your Plan when an Emergency occurs? If it's the former, then it fits this requirement and we would propose the SDT use 'disseminate' or 'issue' for the term. However, if it is the latter, then it doesn't belong in this requirement but perhaps in R6. It seems that the intent could be the latter since the SDT used implement again in Part 2.1 in conjunction with activate. The Emergency Operating Plan, specified in R2, should include the requirement to notify

Organization	Yes or No	Question 5 Comment
		the BA's RC of its current and projected System conditions. R6 would then simply require implementation of the plan. (See our comment in Question 11 below.)Part 2.3. is not clear. An emergency plan that includes procedures, processes and strategies, may not need to be revised for every change in the BA's Balancing Authority Area. The requirement does not include any periodic review. Is the intent of the SDT that the process include some periodic review or is that entirely up to the BA? As currently stated, the scope is entirely too broad.EOP-002-3.1 R5. which states "A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities." does not appear to be covered in R2 as indicated in the Mapping Document. This requirement should be included in this standard or included in the BAL standards in Project 2010-14.2 Periodic Review of BAL Standards. Delete the 'as' in the 2nd line of M2 between the 'have' and 'evidence'.
Florida Municipal Power Agency	No	Similar to comments on Question 2, if the RC is retained as an approval authority, then, the standard needs to better describe change management and what changes the RC is to review and approve.
Duke Energy	No	See Duke Energy comments on question 2. In addition we suggest the following rewording of R2.2,"Procedures, processes, or strategies to prepare for and mitigate Emergencies including a list for consideration, that addresses at a minimum:"
Southern Company: Southern Company Services, Inc.; Alabama Power	No	Southern does not believe all of the "minimum" set of elements outlined in R2.2 should be included for the BA. EOP-001-b R4 states, "Each

Organization	Yes or No	Question 5 Comment
Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan." Southern also believes verbiage from the current version that states that only applicable requirements for an entity are to be included in a Plan should also be stated in this revised requirement. Some of the areas of concern in R2.2 are: o R2.2.2 and R2.2.3: What is the difference between Voluntary Load reductions and Public appeals? o R2.2.4: What governmental programs is the SDT referring to? o R2.2.6: What customer fuel switching? Why is this part of a minimum required set of Plan content since it is our experience that this is not a widespread option for most entities? Southern recommends an additional requirement being added that requires the GOP to provide the data to the BA.
SERC OC Review Group	No	The OC Review Group is concerned with the phrase "At a minimum" as it is possible that certain elements may not be applicable to a certain TOP. It is recommended that the term "applicable" be utilized. Current R2 language: Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: Proposed R2 language: Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. The Emergency Operating Plan shall include the applicable elements when developing its Emergency Operating Plan:
ACES Standards Collaborators	No	(1) As stated in early comments, we do not support the RC approval process because it is primarily an administrative function. (2) Has the drafting team considered the situation where an entity may have load in two different RC Areas? Would they need to have two separate plans and two separate approvals from each RC? What happens if there are three RCs? There are several entities in North America that operate in several regions. This

Organization	Yes or No	Question 5 Comment
		standard is proposing a highly complicated approval process that is unnecessary for reliability.
DTE Electric	No	The end of the first sentence “capacity and Energy Emergencies” should be “Capacity and Energy Emergencies” since Capacity Emergency and Energy Emergency are both defined terms in the NERC Glossary. EOP-001-2.1b Attachment 1 listed “Elements for Consideration in Development of Emergency Plans”. Since the BA only had to consider the elements, those that were not applicable did not need to be addressed in the plan. As written, EOP-011 R2 requires the BA to develop procedures, processes or strategies for items that would not apply to their BA area. Consider replacing “At a minimum, the Emergency Operating Plan shall include:” with “As applicable to the Balancing Authority, the Emergency Operating Plan shall include:”. To show compliance, the BA would respond in the RSAW that certain elements were considered but not applicable. This comment is complementary to the suggestion in comment 13 below regarding EEA levels. Consider adding 2.2.10: “The appropriate conditions under which NERC Energy Emergency Alerts are to be requested.”
ISO/RTO Standards Review Committee	No	We agree with the general intent of R2, but have the following comments: R2.2 requires the BA to develop procedures, processes or strategies to prepare for and mitigate emergencies. Thus, the actionable obligations under 2.2 are the development of procedures. Requirements 2.2.1-2.2.9 are intended to establish a non-exclusive list of means to address the emergencies for which the entity is to have related procedures/plans/strategies. With respect to R2.2.2-R2.2.9, the standard achieves its goal, because those requirements list ways / means to address the emergency, and then 2.2 requires the entity to have plans to utilize those means to mitigate the emergency. However, R2.2.1 does not accomplish this goal, because, as written it does not establish a means of addressing the emergency. Rather, it simply identifies characteristics of

Organization	Yes or No	Question 5 Comment
		generating units. In order to make sense under the standard, R2.2.1 needs to be revised to make it clear that the entity is to apply generating unit characteristics in some context for use in mitigating an emergency. For example, it could be revised as follows (add highlighted language):2.2.1. Appropriate utilization of generating resources in its Balancing Authority Area taking into consideration all relevant until characteristics, including, but not limited to, the following:2.2.1.1. capability and availability;2.2.1.2. fuel supply and inventory concerns;2.2.1.3. fuel switching capabilities;2.2.1.4. environmental constraints.In addition to the above context comment, we recommend the SDT discuss how this standard can be practically implemented, and consider whether the standard can actually achieve some of the underlying objectives. First, there are terms such as “extreme weather” and “coordinate” that are commonly used in the industry - but may not be precise enough in a mandatory requirement associated with compliance. There is no defined term of what extreme weather is and what may be considered extreme in one geographic location may not be extreme in another. For example, one would not expect a large metropolitan area in the South, to have a massive fleet of ice and snow removal equipment on stand-by to clear roads for a 1 in 100 year ice/snow storm. Such should also be considered for the electric industry. The SDT should have a clear way to communicate their expectations to the entities impacted by this standard on how to interpret for them what is an appropriate extreme event. In addition, there are numerous instances where entities are required to coordinate with other entities on emergency plans. However, there is no explanation of what constitutes appropriate coordination. Without guidance on how entities must coordinate, it will be difficult for entities to know the nature and degree of coordination necessary to meet such requirements. Lastly, there should not be an expectation that Transmission Operators, Balancing Authority and Reliability Coordinators will have authority over a Generator Operator’s

Organization	Yes or No	Question 5 Comment
		decisions to reserve its fuel supplies to meet plans developed by the Balancing Authority in advance of any potential emergency conditions. Generators make economic decisions on what and how much fuel to burn. We do not interpret this standard as having any mandatory requirement for any entity to determine when they will or will not run their units to preserve any particular fuel source. On the other hand, if the expectation is that a BA needs to have an Emergency Operating Plan to mitigate resource constraints under insufficient fuel supply situation, then the only option is rotational load shedding during a prolonged period of fuel supply deficiency after all other measures have been exhausted. a. The intent of and linkage between R2, Part 2.2, its sub-parts 2.2.1 and those parts listed under 2.2.1 are unclear. The last sentence in R2 says: “At a minimum, the Emergency Operating Plan shall include:2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum:2.2.1 Generating resources in its Balancing Authority Area 2.2.1.1 Capacity and availability It is unclear on what’s expected from 2.2 when it asks for procedures, etc. to prepare for and mitigate Emergencies, then 2.2.1 starts off by saying “Generating resources...” Does it mean having procedures, etc. to mitigate Emergencies caused by generating resource deficiency? The whole R2 and its parts need to be worded to provide clarity. b. All the parts under Part 2.2.1 are unclear as to what it is that the BA is supposed to guard against. For example, is the BA supposed to prevent the generating resource shortage caused by fuel supply and inventory concern (Part 2.2.1.2) or by environmental constraints (Part 2.2.1.4)? Under these conditions, we are unable to see how a BA can hope to have Emergency plans or procedures in place to mitigate prolonged resource shortage caused by these events, some of which are unpredictable and whose mitigation can be out of a BA’s capability and control. If a BA is unable to mitigate the adverse impact, shedding firm load may well be the last resort. The standard needs to have this provision to ensure the BA does not

Organization	Yes or No	Question 5 Comment
		become liable for events that it did not cause or over which it had any control.
Florida Power & Light	No	This new requirement is too prescriptive, specifically requirement 2.2 where it defines minimum requirements a BA should include in the Emergency Operating Plan. Some of these requirements may not apply to all BAs.
Idaho Power Company	No	Some environmental constraints are required to comply with at all times. For these constraints, NERC cannot dictate their violation. Redispatch of generation should be a BA function.
Xcel Energy	No	R1 and R2 language is strict in that an entity's EOP "shall include" elements defined in R1.1 to R1.3 and R2.1 to R2.3 respectively. What will happen in a situation where one of those elements does not apply to an entity? This standard is implying that all the elements identified in R1.1 to R1.3 and R2.1 to R2.3 must be included in the EOP whether they are applicable or not. The current EOP-001 R4 allows for in its Attachment 1 to be omitted if they are not applicable ("shall include the applicable elements"). We feel like the new EOP-011 standard should include similar language to allow for this flexibility. Could the Standard Drafting Team respond why the language in EOP-011 R1 and R2 was written to be more restrictive than the current EOP-001 R4 and whether items in R1.1 to R1.3 or R2.1 to R2.3 could be omitted from an EOP if found to be not applicable to an entity? Additionally, In Requirement 2.2.4. it is unclear what "Governmental programs" is referring to. This term is not descriptive enough in this context to understand clearly what is being asked for. This appears to be a carry over from EOP-001 Attachment 1 Item 12 Requests of government which reads "Requests to appropriate government agencies to implement programs to achieve necessary energy reductions." If this is the case, we suggest that the language in R2.2.4 be modified to "Governmental

Organization	Yes or No	Question 5 Comment
		programs to reduce Load". Additionally, the word "develop" should be removed from the requirement. Every entity should have a plan today. It should be maintained and implemented. IF an entity does not have a plan, it will have to develop one to have one to implement. The requirement does not need to address this issue.
Wisconsin Electric	No	The RC should not be the approval authority for the BA emergency plan. Given the required minimal inclusions listed in the draft standard, it's not clear why an RC would need to approve or ensure any type of coordination. As an example, why would an RC have to approve a procedure, process, or strategy for conducting public appeals, government programs, or reduction of internal utility energy use? If an RC has specific points of necessary coordination, why not simply require the RC to develop the elements the entities in their RC area need to coordinate? Changing to the wording of 2.2.1.1 is required; currently it does not flow with 2.2.
City of Tallahassee	No	TAL does not understand the intent of R2.2.4 (Governmental programs) in an emergency context. As written, it appears the language suggests entities plan for emergencies with an expectation of assistance from government programs. It is our belief that our plan should accommodate the worst case scenario. Also, requiring the RC to approve the plan places an administrative burden on both the entity and the RC.
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Hydro One	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Pepco Holding Inc.	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Bonneville Power Administration		BPA believes clarfication is needed so that a BA may reduce load either directly or through TOP as designed with regard to 2.28 and 2.27
Public Service Enterprise Group		As described in our response to question 17 that addresses changes to Alert Level 2, change 2.2.7 as follows: “Use of [STRIKE:Interruptible Load, curtailable Load and demand response][ADD controllable and dispatchable Demand Side Management Load];”
Consumers Energy Company		N/A to SC&M Department

6. The EOP SDT has developed proposed Requirement R2, Part 2.2.8 as a process to include manual Load shedding plan coordination. Do you agree that Requirement R2, Part 2.2.8 clearly defines required performance? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: In Requirement R2 Part 2.4.8., the EOP SDT has added the term "Operator-Controlled" preceding the language "manual Load shedding," as it was in the currently-enforced standard, EOP-003-2 Requirement R8. The EOP SDT also agrees that the intent of UFLS is meant as all automatic Load shedding, including UVLS, if applicable; but to still largely maintain separate "plans" for manual and automatic Load shedding. It is the EOP SDT's intention that entities would strive to maintain an operator-controlled manual Load shedding plan that is largely separate and distinct from their automatic Load shed plans. The EOP SDT also understands that when, for example, localized Load shedding is needed, that it may need to include feeders that are part of any automatic Load shed system. Conversely, for Capacity Emergencies, if operator-controlled Load shedding is needed, it is desirable to avoid feeders with automatic Load shedding, such that automatic Load shedding functionality is maintained.

Organization	Yes or No	Question 6 Comment
MRO NERC Standards Review Forum	No	We believe that the "automatic Load shedding" is either UFLS or UVLS (and maybe an SPS/RAS). It is very hard to (and impossible) "coordinate" an automatic system with a manual system. Since R2.2.8 is an element of the Emergency Operating Plan, recommend R1.2.5 to read: Manual Load shedding plan(s) incorporated to minimize the use of automatic Load shedding;". This will allow the entity to have a preconceived (pre-planned) process for when the risk is higher that an automatic Load shedding may occur.
Dominion	No	Dominion is concerned that this could be read as requiring manual (human at station) load shed as opposed to automatic (SCADA) when we believe the intent is to coordinate so as to avoid overlap with UFLS and UVLS programs. We suggest 2.2.8 read as 'Operator controlled manual Load shedding plan coordinated to minimize the

Organization	Yes or No	Question 6 Comment
		use of UFLS and UVLS automatic Load shedding.' In which operator controlled manual load shedding was used in EOP-003-2.
SPP Standards Review Group	No	The phrase "coordinated to minimize the use of automatic Load shedding" in Requirement 2, Part 2.2.8 is not clear. Is the intent to coordinate the manual Load shedding plan with those locations that have automatic Load shedding installed so as not to duplicate the same Load in both manual and automatic plans? Or is the intent to develop a manual Load shedding plan that will be enacted quickly enough so that automatic Load shedding is minimized? If it is the former, we suggest revised language for Part 2.2.8.: "Manual Load shedding plan coordinated to minimize the use of locations with automatic Load shedding;". We may even go further to propose deleting the phrase "to minimize the use of automatic load shedding" entirely as this seems to be a bit of editorializing. If it is the latter, then the reason for having a manual Load shedding plan is immaterial in the standard. It definitely needs to be in your Emergency Operating Plan, just not in the standard.
Florida Municipal Power Agency	No	Similar to 1.2.5, the automatic load shedding to be coordinated with is UFLS, not UVLS; hence, the bullet should be made specific to the type of load shedding to be coordinated with. It is unrealistic to expect a coordination of load shedding between UFLS and UVLS, that is, in areas where both UVLS and UFLS is needed, there will be overlap of the distribution feeders, i.e., there will be individual feeders that will have both UFLS and UVLS on it.
Northeast Power Coordinating Council	No	Same comments as provided in Question 3 for Part 1.2.5 on the need to expand this part to more clearly stipulate who or which plans a BA needs to coordinate its manual load shedding plan with.
Duke Energy	No	See Duke Energy comments on question 3.
Southern Company: Southern Company Services, Inc.;	No	Southern does not agree that R2, Part 2.2.8 clearly defines required performance. Southern recommends that the SDT modify the rationale included in the standard or

Organization	Yes or No	Question 6 Comment
Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		the technical background and rationale document to clearly explain the intent of the requirement.
SERC OC Review Group	No	The OC Review Group recommends that adding “Operator controlled” further clarifies R2, Part 2.2.8Current language: 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; Proposed language: Operator controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding;
ACES Standards Collaborators	No	(1) We would like clarification on minimizing the use of automatic load shedding. Manual load shedding could be an operator pushing a button to initiate load shedding. We believe the standard is attempting to state that manual load shedding should be planned to minimize the use of UFLS or UVLS. However, the standard is not this specific and needs to be clarified. (2) We are concerned about the ambiguous term of coordination and the varying compliance monitoring approaches from regional entities. We would like to see compliance guidance or an RSAW to state how this will be evaluated.
ISO/RTO Standards Review Committee	No	Same comments on R1.2.5 under Q3 on the need to expand this part to more clearly stipulate with whom or which plans a BA needs to coordinate its manual load shedding plan.

Organization	Yes or No	Question 6 Comment
Florida Power & Light	No	Requirement not clear. Is this requirement intended to use the manual load shed to prevent automatic load shed or is it to ensure that the same resource is not used for manual and automatic load shed?
PacifiCorp	No	R2, Part 2.2.8 does not clearly define required performance. In the proposed requirement, the language 'coordinated to minimize the use of automatic Load shedding' does not provide sufficient guidance on the intended load shed policy. The Drafting Team should develop language which provides more specific guidance on how manual Load shedding should be coordinated, and provide a more specific performance measure than 'minimize the use' of automatic Load shedding. With respect to the latter, the Drafting Team may want to specifically reference minimizing dependence on under voltage and under frequency Load shedding plans if that is the intention.
Bonneville Power Administration	No	BPA believes this applies only if a BA has direct-control load shedding.
Hydro One	No	The Balancing Authority should gain documented approval from the Load Serving Entity as part of their coordination.
Idaho Power Company	No	This coordination may in fact require to shed load manually that was included in the Automatic Load Shedding plan. We believe the Balancing Authority should have adequate load shedding capability and capacity. As part of 2.2, it should just say "Processes for manual load shedding."
Xcel Energy	No	There is no defined performance because of the use of the word "minimize". Does this mean any use of automatic load shedding violates the standard? If so, entities should remove any automatic load shedding capability so they do not violate the standard. However, that will put the interconnection at greater risk, which is not the goal of the standards. As written, there is no clear measurement process. It would have to be argued on a case by case basis and an auditor/regulator can argue any

Organization	Yes or No	Question 6 Comment
		automatic load shedding violates the standard. This is a detail that cannot be properly addressed in a standard as the specifics will vary with each entity.
Independent Electricity System Operator	No	Same comments on R1.2.5 under Q3 on the need to expand this part to more clearly stipulate with whom or which plans a BA needs to coordinate its manual load shedding plan.
Public Service Enterprise Group	No	The requirement for a coordinated manual Load shedding plan is a good one. However, the BA should coordinate its plan with its LSEs, DPs, and their respective TOPs. TOPs should be added to the BA coordination because a manual Load shedding plan is also required in R1 for TOPs. The two entities (TOP and BA) should coordinate their manual Load shedding plans among themselves before submitting such plans to their RC for approval. Part 2.2.8 should therefore be modified as follows: "Manual Load shedding plan coordinated [ADD:among its Load Serving Entities and Distribution Providers and their respective Transmission Operator(s)] ...."
Tacoma Power	No	Tacoma Power is unsure if the intent is: a) for the System Operator to minimize manually shedding facilities that have automatic load shedding equipment installed in lieu of facilities that do not, -OR- b) to utilize manual load shedding (preemptively) to attempt to forestall automated load shedding from occurring.
Wisconsin Electric	No	It is not clear what or with whom coordination is required. The proposed standard "Rationale for R2" section indicates that TOP and BA load shedding "sometimes" needs to be coordinated. However, neither R1 (TOP requirement) nor R2 (BA requirement) explicitly require coordination between the two.
City of Tallahassee	No	TAL is confused by R2.2.8. Is the intent not to overlap manual and automatic (UFLS) load shed tools (i.e. feeder circuits) or is the intent to require manual load shedding prior to activation of automatic load shedding? The verbiage does not specify who must be part of the coordination effort.

Organization	Yes or No	Question 6 Comment
Lincoln Electric System	No	Refer to comment in Question #3.
Arizona Public Service Company	Yes	
DTE Electric	Yes	
Manitoba Hydro	Yes	
Pepco Holding Inc.	Yes	
Consumers Energy Company		N/A to SC&M Department

7. The EOP SDT has developed proposed Requirement R2, Part 2.2.8 without time measure. The currently-enforce EOP-003-2, Requirement R8 states, "… timeframe adequate for responding to the emergency." Do you support Requirement R2, Part 2.2.8 without a time measure? If not, please provide specific suggestions for improvement, including alternate language.

Summary Consideration: The EOP SDT agrees that the time frame may vary by the request of the Reliability Coordinator or Transmission Operator as a directive. If a directive cannot be performed in the time frame requested, the process (per TOP-001-1 and IRO-001 [as well as other standards]) is to report this information back to the Reliability Coordinator and Transmission Operator so further actions can be taken to mitigate the event. The Rationale for Requirement R2 addresses that an Emergency plan may sometimes require coordination between the Balancing Authority and the Transmission Operator. The EOP SDT held discussion to emphasize the importance of coordination between the Balancing Authority/Transmission Operator in any type of event pertaining to manual Load shed and in addressing how a directive should be handled, regardless of the content of the directive.

Organization	Yes or No	Question 7 Comment
SPP Standards Review Group	No	One of the issues identified in previous events has been that some entities have manual Load shedding plans that require dispatching personnel to dispersed locations to implement the plan. The standard should include a requirement that manual Load Shedding be able to be implemented in time to mitigate the Emergency. We suggest the requirement include that the Manual Load shedding plan be capable of being implemented by an operator remotely. This addresses the issue of not being able to respond quickly to a given situation while at the same time eliminating the ambiguity of maintaining the existing language in EOP-003-2, R8.
ACES Standards Collaborators	No	(1) We support manual firm load shedding without a specific time measure. However, we are concerned about the ambiguous term of coordination and the varying compliance monitoring approaches from regional entities. We would like to see compliance guidance or an RSAW to state how this will be evaluated. (2) Part 2.2.9 needs to be revised. The clause "if not covered by other elements of the plan" is confusing and does not need to be in a requirement. Either the BA needs to have a

Organization	Yes or No	Question 7 Comment
		strategy for extreme weather or not. This language only adds confusion and needs to be removed.
PacifiCorp	No	PacifiCorp supports use of language similar to EOP-003-2 R8 and the language "... timeframe adequate for responding to the emergency." PacifiCorp annually updates detailed analyses which produce block load shed plans and instructions. Operator training, combined with block load shed plans and instructions, ensures operators are capable of implementing load shedding in a timeframe adequate for responding to an emergency.
Idaho Power Company	No	An entity could lean on the interconnection for up to 30 minutes per the proposed BAL-001-2 as long as the interconnection was stable. BAL-002-1 says that the BA shall return its ACE to zero or the pre-disturbance point if ACE was negative within 15 minutes. This requirement needs to be more specific possibly using 30 minutes as in the proposed BAL-001-2.
Tacoma Power	No	The current EOP-003-2 R8 language "timeframe adequate for responding to the emergency" should remain. Load shedding plans that are not viable (i.e. the System Operator has no hope of actually executing the plan quickly enough to mitigate the emergency) are useless. I fear that without this measurement, plans that are not actually useful may be created.
Arizona Public Service Company	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	Yes	Other standards adequately cover the time frame requirements.

Organization	Yes or No	Question 7 Comment
Company Generation; Southern Company Generation and Energy Marketing		
SERC OC Review Group	Yes	The SERC OC Review Group respectfully recommends that the SDT consider changing M2 to align with M1 by identifying the Reliability Coordinator as the approving entity. Current M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R2. Proposed M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R2.
Northeast Power Coordinating Council	Yes	Same comment as for Part 1.2.5 in the response to Question 4.
ISO/RTO Standards Review Committee	Yes	Same comment for Part 1.2.5 under Q4, above.
Xcel Energy	Yes	The time frame is determined by the emergency. The current language is impossible to fairly enforce. Therefore, it should be removed. We support the drafting team's position on this issue.
Independent Electricity System Operator	Yes	Same comment for Part 1.2.5 under Q4, above.

Organization	Yes or No	Question 7 Comment
Xcel Energy	Yes	The time frame is determined by the emergency. The current language is impossible to fairly enforce. Therefore, it should be removed. We support the drafting team's position on this issue.
Independent Electricity System Operator	Yes	Same comment for Part 1.2.5 under Q4, above.
Pepco Holding Inc.	Yes	Don't need to duplicate the same requirement in different Standards.
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
Duke Energy	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	
Public Service Enterprise Group	Yes	

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Yes	
Wisconsin Electric	Yes	
City of Tallahassee	Yes	
Consumers Energy Company		N/A to SC&M Department

8. **The EOP SDT has developed a requirement to address a directive from Paragraph 548 of FERC Order No. 693. This directive states "…the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity." Requirement R3 requires the Reliability Coordinator to coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area to provide a wide-area perspective and to ensure that they are compatible and support reliability in the Reliability Coordinator Area. This also relates to Requirement R3, Part 3.3 of EOP-001-2.1b, which requires coordination of plans. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.**

Summary Consideration: The EOP SDT has reviewed the comments below and, in coordination of the other comments received, has deleted Requirement R3. The EOP SDT has placed the requirement to coordinate plans on the Balancing Authority (Requirement R2 Part 2.5) and on the Transmission Operator (Requirement R1 Part 1.3). The following language was added to Requirement R1 Part 1.3, "Strategies for coordinating Emergency Operation Plans with impacted Transmission Operators and impacted Balancing Authorities." The following language was added to Requirement R2 Part 2.5, "Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators."

Organization	Yes or No	Question 8 Comment
SPP Standards Review Group	No	While we agree with the intent, the language of the proposed requirement R3 only requires coordination within the Reliability Coordinator Area. Especially for entities on the seams between Reliability Coordinator Areas, it is essential that these plans be coordinated with neighboring Reliability Coordinators. We propose the following language for R3: "Each Reliability Coordinator shall review the Emergency Operating Plans of the entities in its Reliability Coordinator Area and with neighboring Reliability Coordinators to ensure that the plans are compatible and support reliability of the Bulk Electric System." This proposal also eliminates potential issues with the use of the term 'coordinate'.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	No	We support the proposed requirement, and we agree with the intent of R3 and R4 (to have Emergency Operating Plans by the TOPs and BAs coordinated, and approved by the RC). However, we believe putting the coordination responsibility solely on the RC (as Requirement R3 suggests) is neither sufficient nor appropriate. The TOPs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other TOPs and BAs in the RC Area. Likewise, the BAs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other BAs and TOPs in the RC Area. The RC's role, then, will be to assess if such coordination occurred, and approve or disapprove the EOPs. We suggest R3 be revised to explicitly state the responsibilities for the TOPs and the BAs (or any other entities within the RC's Area) to coordinate their EOPs. Alternatively, a new requirement may be created to capture such responsibilities.
Duke Energy	No	Duke Energy suggests replacing "coordinate" with "review" in R3 as follows:" Each Reliability Coordinator shall review the Emergency Operating Plans of the entities in its Reliability Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area." This provides consistency with the language in R5 of EOP-006-2 where an RC reviews the Restoration plans to determine if they are compatible and support the Reliability of the RC Area.
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 does not agree that the Reliability Coordinator should be obligated to review/approve all TOP and BA Emergency Operating Plans. This requirement/standard places an administrative burden on Reliability Coordinators to review / approve numerous Emergency Operating Plans. Historically, RC approval has not been required and registered TOPs/BAs have implemented their emergency plans to mitigate the emergencies without negatively impacting neighboring TOPs/BAs, so it is not clear why RC approval is now required. Southern requests the SDT reconsider RC approval. If the requirement remains: o The term "coordinate" should be changed to "review" because "coordinate" implies a more active involvement in the development of the Operating Plans, including such items as facilitating

Organization	Yes or No	Question 8 Comment
		development meetings, etc. That would be required to merely review and approve/disapprove a Plan. o The SDT should more clearly, in the requirement itself or in the Rationale, describe what Plan parameters they feel should be evaluated for “compatibility” so that there will be consistency among the RC review activities.
ACES Standards Collaborators	No	Why not require the RC to post its emergency operating plans and notify all of the entities in its area of any changes? The TOP and BA could align their emergency plans with the RC and then the RC could review these plans for conflicts. The RC already is required to perform emergency operations training with other entities, so requiring an approval process is administrative and unnecessary.
Bonneville Power Administration	No	BPA believes this approval adds another layer to a wide area responsibility when the issue is mostly between smaller regions. The RC approval is not needed of 40 entities. The RC should direct load shedding through their own plan but they should have copies of the individual plans.
Xcel Energy	No	It is unclear how the RC will coordinate plans that will be addressing different issues and owned by different entities. Will the RC require that the entities only use a certain section of their plan if another entity is also experiencing an emergency at that time? While we support the intent of this requirement, it may need a guideline or other guidance document to help the process flow.
Wisconsin Electric	No	Without the RC identifying the points of coordination, it’s not clear how they can “coordinate” between multiple BAs and TOPs. The standard requires the TOPs and BAs to address specific items in their plans and their plans to be approved by the RC. The timing of TOP/BA submission for RC approval will likely be sporadic and the standard requires the RC to provide approval or disapproval within 30 days. It’s not practical for an RC to coordinate plans from multiple BAs or TOPs submitted at different times without the RC issuing some type of guidance that identifies points of coordination.

Organization	Yes or No	Question 8 Comment
Electric Reliability Council of Texas, Inc.	No	Requirement 3 requires the RC to coordinate the relevant plans to “ensure that the plans are compatible and support reliability in the Reliability Coordinator Area.” The RC review cannot “ensure” reliability. Furthermore, reliability is undefined, and, therefore ambiguous in this context. The wording should be revised as follows (consistent with EOP-006-2 R5) to mitigate these issues:R3. Each Reliability Coordinator shall review the Emergency Operating Plans required by EOP-011 of the entities within its Reliability Coordinator Area. [Violation RiskFactor = Medium] [Time Horizon = Operations Planning]R3.1. The Reliability Coordinator shall determine whether the entity’s Emergency Operating Plan is coordinated and compatible with the Reliability Coordinator’s Emergency Operating Plan and other entity’s within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, entity’s Emergency Operating Plan within 30 calendar days following the receipt of the entity’s Emergency Operating Plan. In addition to the RC, TOPs should be required to coordinate their plans with other TOPs and BAs in the RC Area. Similarly, BAs should also be required to coordinate their plans with other BAs and TOPs in the RC area. Load shed plans, or other transmission emergencies may require coordination at the TOP level for switching and other similar actions. The RC may not have that detailed visibility or have a role in switching instructions or types of load, critical loads, etc. that the TOP manages. Another important example is load shedding coordination - manual/automatic load shed coordination involves TOP to TOP coordination. For these reasons TOs and BAs should have a coordination role - limiting coordination to just the RC is inappropriate. The revised standard does not include the Communication Protocols from EOP 001 R4.1. While specific communication protocols related to prevention of miscommunications is addressed in the COM standards, it is important that appropriate communications take place between the appropriate entities during emergency operations to support adequate situation awareness for all relevant entities. The EOP standards can facilitate this by making sure all relevant functional entities are identified for issuing and receiving the relevant notices/communications. While the standard does establish relationships between RC, BA, TOP’s; DPs and GOPs are not implicated, and it is arguable that

Organization	Yes or No	Question 8 Comment
		these entities should have appropriate situational awareness during emergency operations. For example, after the RC notifies the BA, and TOP, likewise the BA and TOP should notify affected DPs and GOPs of the particular emergency. This promotes situational awareness. Additionally while DPs and GOPs play a lesser role, consideration should be given to their inclusion at appropriate levels. DPs should have emergency plans for those emergency actions they need to take, i.e. load shed voltage reduction. GOPs have a role to play and are more appropriate for addressing fuel supply and inventory, fuel switching capabilities, environmental constraints, reduction of internal usage, and most importantly WEATHERIZATION of units. At a minimum, they need to provide this information to the BAs. This is especially true in organized market regions (i.e. ISOs/RTOs). Including DPs and GOPs as appropriate is consistent with their applicability in other standards, such as the communication standards.
ISO/RTO Standards Review Committee	Yes	We support the proposed requirement, and we agree with the intent of R3 and R4 (i.e., to have Emergency Operating Plans by the TOPs and BAs coordinated, and approved by the RC). However, we believe that putting the coordination responsibility solely on the RC (as Requirement R3 so suggests) is neither sufficient nor appropriate. The TOPs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other TOPs and BAs in the RC Area. Likewise, the BAs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other BAs and TOPs in the RC Area. The RC's role, then, will be to assess if such coordination occurred, and approve or disapprove the EOPs. We suggest R3 be revised to explicitly state the responsibilities for the TOPs and the BAs (or any other entities within the RC's Area) to coordinate their EOPs. Alternatively, a new requirement may be created to capture such responsibilities.
Independent Electricity System Operator	Yes	We support the proposed requirement, and we agree with the intent of R3 and R4 (to have Emergency Operating Plans by the TOPs and BAs coordinated, and approved by the RC). However, we believe putting the coordination responsibility solely to the RC (as Requirement R3 so suggests) is not sufficient or appropriate. The TOPs themselves

Organization	Yes or No	Question 8 Comment
		should be responsible for coordinating their Emergency Operating Plans (EOPs) with other TOPs and BAs in the RC Area. Likewise, the BAs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other BAs and TOPs in the RC Area. The RC's role, then, will be to assess if such coordination occurred, and approve or disapprove the EOPs. We suggest R3 be revised to explicitly state the responsibilities for the TOPs and the BAs (or any other entities within the RC's Area) to coordinate their EOPs. Alternatively, a new requirement may be created to capture such responsibilities.
CenterPoint Energy	Yes	CenterPoint Energy agrees with the proposed coordination role for the Reliability Coordinator.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
SERC OC Review Group	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 8 Comment
American Electric Power	Yes	
Hydro One	Yes	
Idaho Power Company	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	
American Transmission Company, LLC	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Lincoln Electric System	Yes	
City of Austin dba Austin Energy	Yes	
ReliabilityFirst		ReliabilityFirst offers the following comments for consideration:1. Requirement R3 - ReliabilityFirst believes the intent of Requirement R3 (specifically the term “coordinate”) is ambiguous and will lead to potential interpretation problems. ReliabilityFirst believes this “coordination” is actually addressed in Requirement R4 in

Organization	Yes or No	Question 8 Comment
		which the Reliability Coordinators will be reviewing all Emergency Operating Plans and approving/disapproving them accordingly if there are any “coordination” type issues. ReliabilityFirst recommends removing Requirement R3 from the draft standard.

9. In addition to Requirement R3, the EOP SDT proposes an additional requirement, Requirement R4, applicable to the Reliability Coordinator to address the Order No. 693, Paragraph 548 directive. The proposed Requirement R4 requires the Reliability Coordinator to approve or disapprove Transmission Operator and Balancing Authority Emergency Operating Plans within 30 days of submittal. Since these Emergency Operating Plans are submitted on an agreed-upon schedule, the EOP SDT believes that 30 days is adequate time for the Reliability Coordinator to assess the plans. Do you support the proposed changes? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: The EOP SDT found that most commenters agreed with the 30-day time frame for the Reliability Coordinator to approve or disapprove Emergency Operating Plans. There were several questions raised as to the process if the plan is not approved by the Reliability Coordinator. The EOP SDT's intent is that the implementation window will allow time for the Balancing Authority's or Transmission Operator's plan(s) to initially be approved. Further, the EOP SDT's intent is that the Balancing Authority's or Transmission Operator's current Reliability Coordinator-approved Emergency Operating Plan would remain in effect until the revised plan gets approved. There were a few comments disagreeing with Reliability Coordinator approval of Balancing Authority and Transmission Operator Emergency Operating Plan(s). The FERC directive in Paragraph 548 of Order 693 mandates that the Reliability Coordinator be included as an applicable entity; while not specifically mandated that this meant plan approval by the Reliability Coordinator, the EOP SDT still feels approval by the Reliability Coordinator reduces risk to reliability.

Organization	Yes or No	Question 9 Comment
SPP Standards Review Group	No	While we support the concept of the requirement, we propose a rewording to improve clarity. We suggest: "Each Reliability Coordinator shall approve, or disapprove with stated reasons for disapproval, Emergency Operating Plans submitted by Transmission Operators and Balancing Authorities within 30-calendar days of submittal." M4 would need to be modified to parallel this language. Additionally, the question refers to an 'agreed-upon schedule' for submittal of the plans. We cannot find a reference to this agreement in the standard. Plans will need to be revised and then subsequently submitted for review and approval but there is nothing mentioned about an agreed-upon schedule between the Reliability

Organization	Yes or No	Question 9 Comment
		Coordinator and the Balancing Authority or Transmission Operator. Perhaps the SDT should look at the language contained in EOP-005-2 outlining timing for the submittal and approval of restoration plans by the Transmission Operator and Reliability Coordinator, respectively, for parallels for submitting and approval of Emergency Operating Plans.
Northeast Power Coordinating Council	No	It is not clear what an entity should do if its plan is not approved, especially if an entity is revising its plan to address a known deficiency or required changes to its existing plan. In this circumstance simply using the existing plan does not seem appropriate. We agree with the proposed R4, on the assumption that coordination between TOPs/BAs have occurred prior to the submittal of the individual EOPs. Please refer to our comments to Question 8.
ACES Standards Collaborators	No	(1) Does the drafting team really think that 30 days is sufficient amount of time to review potentially dozens of plans? What if they were all submitted during peak season? What is more important to reliability - reviewing documentation or the actual operation of the Bulk Electric System? The timeframes are administrative in nature and a burden on all entities that would have to comply. We strongly urge the drafting team to consider a different approach.
PacifiCorp	No	While PacifiCorp agrees with the RC having a 30 day period to review a TOP or BA Emergency Operating Plan, it appears that an applicable entity could be out of compliance either during the RC's review, or if the RC withholds approval until certain modifications to the Emergency Operating Plan are completed. The language in R1 and R2 require that a TOP or BA have a "Reliability Coordinator-approved" Emergency Operating Plan, providing no room for interpretation if the RC fails to meet its deadline or additional

Organization	Yes or No	Question 9 Comment
		coordination between neighboring entities is required. This puts a TOP or BA at risk that the RC will reject the Emergency Operating Plan simply to meet its deadline and maintain compliance with R4. The EOP SDT should revise R4 to allow the Reliability Coordinator to either: (1) approve; (2) approve pending modification; (3) or reject a proposed Emergency Operating Plan. This modification will address any issues that may arise out of either the Reliability Coordinator's ability to complete its review in the 30 day review period, and allow an opportunity for the Reliability Coordinator to coordinate between neighboring TOPs and BAs.
American Electric Power	No	In the FERC Order No. 693, Paragraph 632 (EOP-006-1), FERC has clearly directed that the Reliability Coordinator be involved in the development and approval of restoration plans. However, FERC did not make this distinction that the Reliability Coordinator approve the EOP (EOP-001-0) plans (Paragraph 547).Rather than what is currently proposed, the RC needs to be involved in the development and coordination of Emergency Operating Plans as opposed to approving those plans.
Idaho Power Company	No	Agree that the plans should be coordinated but I do not believe that the RC should formally approve the plan. If by approval the RC is saying they have performed R3 "Each Reliability Coordinator shall coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area" and not found any incompatibilities or reliability concerns.
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration:Requirement R4 - ReliabilityFirst believes if the Reliability Coordinator disapproves an Emergency Operating Plan not only should they be required to state the reasons, they should also be required to provide specific recommended modifications that would lead to the Plan's

Organization	Yes or No	Question 9 Comment
		approval. ReliabilityFirst recommends the following for consideration "Each Reliability Coordinator shall approve or disapprove, with stated reasons for disapproval [and recommended modifications that would lead to the Plan's approval], Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within 30 calendar days of submittal."
CenterPoint Energy	No	As stated above in response to Question 2, CenterPoint Energy does not agree with the proposed change to require Reliability Coordinator approval of Transmission Operator's Emergency Operating Plans. Paragraph 548 of Order 693 directed the ERO to 1) include the RC as an applicable entity, and 2) consider SoCal Edison's suggestion. The SoCal Edison comment in Paragraph 546 states that NERC "should receive input from stakeholders on which requirements should be exclusive to the transmission operator or balancing authority with the reliability coordinator responsible only for collecting and incorporating this information into its overarching plan". CenterPoint Energy reading of the directive is that it does not contain the addition of Reliability Coordinator approval and requiring such approval was specifically omitted by the Commission. Therefore, CenterPoint Energy believes this is an unnecessary expansion of FERC's directive in Paragraph 548. CenterPoint Energy strongly recommends Requirement R4 be deleted from the draft standard EOP-011-1.
City of Tallahassee	No	Requiring RC approval will add an administrative burden on each side. If approval is the end result, TAL recommends combining R4 with R3 to make one requirement requiring coordination and approval or disapproval. Recommend 60 days for approval. Although the submittal is on an approved schedule the "RC" is not a single person, but rather a committee. Work products often need to go through a formal committee process to gain "approval". 60 days minimizes the burden.

Organization	Yes or No	Question 9 Comment
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) believes the RC can coordinate plans without having to approve them.
Dominion	Yes	Dominion believes the SDT is assuming the 'plans are submitted on an agreed-upon schedule', there is nothing in the standard that requires this, but we agree 30 days is adequate.
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	If R3 remains, the 30 day review time is appropriate but that the 30 day time period should be prior to any implementation date specified in the BA/TOP Operating Plan. As was acknowledged by FERC in its Order for EOP-006, 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. This concept needs to be captured in the requirement.
ISO/RTO Standards Review Committee	Yes	We agree with the proposed R4, assuming that coordination between TOPs and BAs has occurred prior to the submittal of the individual EOPs. Please refer to our comments/suggestions under Q8, above.
Independent Electricity System Operator	Yes	We agree the proposed R4, on the assumption that coordination between TOPs/BAs have occurred prior to the submittal of the individual EOPs. Please refer to our comments/suggestions under Q8, above.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Florida Municipal Power Agency	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 9 Comment
SERC OC Review Group	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	
Xcel Energy	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	
American Transmission Company, LLC	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
Lincoln Electric System	Yes	

10. The EOP SDT has developed proposed Requirement R5 to have a Transmission Operator that is experiencing an operating Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. This is a corollary requirement to existing EOP-002-3.1, Requirement R3; whereby the Balancing Authority performs a similar notification for its Emergencies. Do you support the proposed Requirement R5? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: The EOP SDT has discussed the comments received and agrees with the commenters that this requirement is parallel to TOP-001-1a and has deleted Requirement R5 from proposed EOP-011-1. The language, "Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an Operating Emergency," has been added to Requirement R1 Part 1.2.1.

Organization	Yes or No	Question 10 Comment
SPP Standards Review Group	No	It may be appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies on its Transmission System within R5. The Emergency Operating Plan, required in R1, should include the requirement to notify the Transmission Operator's Reliability Coordinator of its current and projected System conditions. R5 would then simply require implementation of the plan. (See our comments on Question 2.)We recommend the following for R5: "Each Transmission Operator that is experiencing an operating Emergency on its Transmission System shall implement its Emergency Operating Plan. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]"
ACES Standards Collaborators	No	We do not support the requirement as written. Why can't this notification requirement be included in the emergency operating specified in R1? This would eliminate the need for this requirement.

Organization	Yes or No	Question 10 Comment
American Electric Power	No	AEP believes R5 violates Paragraph 81 Criteria B7, as it is redundant with similar requirements in TOP-001-1a R5. The SDT needs to review the existing standards landscape for additional, potential redundancy.
City of Garland	No	Concern - TOP Operators have full authority and responsibility to deal with emergencies. Also, it is second nature for the operator to notify the RC as soon as he or she is able. Because an emergency is an “emergency”, 1) the operator may be fully occupied dealing with the emergency in real time, 2) may not know the initiating factor that started the emergency until technical personnel (IT, substation, engineering, etc.) investigate, and 3) may not know or be able to “project system conditions”. The concern is that an auditor could say, I listened to the phone recordings, I heard you notify the RC of the current conditions as you knew them but I did not hear you give any projections of return to normal or the system will be in this or that condition in 2 hours or etc. - you are therefore in violation of R5. Recommendation - end the sentence with “communicate the Emergency and the current status.” The RC should have full visibility of the system and see outaged or overloaded elements. If the RC needs additional information beyond what is given, he can question the TOP Operator.
Tacoma Power	No	Tacoma Power would suggest the following modification: ...operating Emergency to communicate “as soon as practical” its Emergency...
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration: Requirement R5 - ReliabilityFirst believes there should be a timeframe associated with how long the Transmission Operator has to communicate the Emergency and its current and projected System conditions to its Reliability Coordinator. In a hypothetical situation, without a timeframe associated with the requirement, a Transmission Operator can communicate the Emergency 10 hours after the fact and still be compliant. ReliabilityFirst does not believe this meets the reliability intent of the requirement. ReliabilityFirst recommends the following for consideration: “Each Transmission

Organization	Yes or No	Question 10 Comment
		Operator that is experiencing an operating Emergency on its Transmission System shall communicate the Emergency and its current and projected System conditions to its Reliability Coordinator [within 30 minutes of the start of the Emergency].
CenterPoint Energy	No	CenterPoint Energy does not believe it is necessary to create a corollary requirement to EOP-002-3.1 R3. Such corollary requirements already exist in standard TOP-001-1a R5 and R8. TOP-001-1a R5 requires the TOP to inform its RC of emergency conditions and to mitigate the emergency if possible, while TOP-001-1a R8 requires the TOP to request emergency assistance from the RC if the TOP is unable to recover on its own. CenterPoint Energy believes the necessary communication between a TOP and its RC to ensure reliability during an Emergency is already mandated. The Company believes the proposed Requirement R5 is redundant based on P81 criteria and should be deleted from the draft standard EOP-011-1.
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) finds the phrase “projected System conditions” unclear. AE prefers the TOP requirement be limited to “current System conditions” which is more aligned with the information a System Operator will have in real-time.
Florida Municipal Power Agency	Yes	The only other issue that may be appropriate to address is timing of the required communication. Maybe something like "as soon as reasonable while not unduly impacting response to the Emergency".
Northeast Power Coordinating Council	Yes	We support the addition of R5 to have a Transmission Operator that is experiencing an operating Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. (Clarification is needed for “projected system conditions.” A definition of this term would help clarify the intent of this statement so that it would not be open ended.)A responsible entity must communicate this to other TOPs and/or BAs that may be impacted by the TOP’s Emergency. How quickly does a TOP that is experiencing an operating Emergency

Organization	Yes or No	Question 10 Comment
		have to “communicate the Emergency and its current and projected System conditions to its Reliability Coordinator”?
ISO/RTO Standards Review Committee	Yes	We support the addition of R5 to have a Transmission Operator that is experiencing an Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. We are indifferent as to who should be responsible for communicating the Emergency to other TOPs and/or BAs that may be impacted by it, as long as this is performed by a responsible entity.
Independent Electricity System Operator	Yes	We support the addition of R5 to have a Transmission Operator that is experiencing an operating Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. We are indifferent as to who should be responsible for communication this to other TOPs and/or BAs that may be impacted by the TOP’s Emergency, for so long as this is performed by a responsible entity.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi	Yes	

Organization	Yes or No	Question 10 Comment
Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
SERC OC Review Group	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	
Idaho Power Company	Yes	
Xcel Energy	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 10 Comment
American Transmission Company, LLC	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Oncor Electric Delivery Company LLC	Yes	

11. The EOP SDT has developed proposed Requirement R6 to have a Balancing Authority that is experiencing a capacity or Energy Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. This is a revision to existing EOP-002-3.1, Requirement R3. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: The EOP SDT agrees with the comments received to add the notification requirement within Requirement R2. The EOP SDT added the language, "Notification to the Reliability Coordinator, to include current and forecasted conditions, when experiencing a Capacity Emergency or Energy Emergency," to Requirement R2 Part 2.2., and deleted Requirement R6 from EOP-011-1.

Organization	Yes or No	Question 11 Comment
SPP Standards Review Group	No	It may be appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies within its Balancing Authority Area within R6. The Emergency Operating Plan, required in R2, should include the requirement to notify the Balancing Authority's Reliability Coordinator of its current and projected System conditions. R6 would then simply require implementation of the plan. (See our comments on Question 5.)We recommend the following for R6: "Each Balancing Authority Operator that is experiencing an operating Emergency within its Balancing Authority Area shall implement its Emergency Operating Plan. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]"
ACES Standards Collaborators	No	We do not support the requirement as written. Why can't this notification requirement be included in the emergency operating specified in R2? This would eliminate the need for this requirement.
DTE Electric	No	The end of the first sentence "capacity or Energy Emergencies" should be "Capacity or Energy Emergencies" since Capacity Emergency and Energy Emergency are both defined terms in the NERC Glossary.

Organization	Yes or No	Question 11 Comment
Xcel Energy	No	In the current EOP standards, a Load-Serving Entity can as for an EEA from the RC. As written, the LSE is not mentioned. Is the SDT therefore assuming that the BA must provide service to all loads within its area under its emergency plan regardless of generator ownership or load service responsibility?
Tacoma Power	No	Tacoma Power would suggest the following modification: ...Energy Emergency to communicate “as soon as practical” its Emergency...
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration: 1. Requirement R6 - ReliabilityFirst has similar concerns with Requirement R6 as stated in the comment to Requirement R5. Also, since Requirement R5 and Requirement R6 are very similar, ReliabilityFirst recommends combining Requirement R5 and Requirement R6 and having them applicable to both the Transmission Operator and Balancing Authority
Florida Municipal Power Agency	Yes	See comments to question 10.
Northeast Power Coordinating Council	Yes	We are indifferent as to who should be responsible for communicating this to other TOPs and/or BAs that may be impacted by the TOP’s Emergency, as long as this is performed by a responsible entity.
ISO/RTO Standards Review Committee	Yes	We are indifferent as to who should be responsible for communicating the capacity Emergency or Energy Emergency to other TOPs and/or BAs that may be impacted by the TOP’s capacity or Energy Emergency, as long as this is performed by a responsible entity.
Independent Electricity System Operator	Yes	We are indifferent as to who should be responsible for communication this to other TOPs and/or BAs that may be impacted by the TOP’s Emergency, for so long as this is performed by a responsible entity.

Organization	Yes or No	Question 11 Comment
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	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	
SERC OC Review Group	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	

Organization	Yes or No	Question 11 Comment
Idaho Power Company	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Lincoln Electric System	Yes	
Consumers Energy Company		N/A to SC&M Department

12. **The EOP SDT has developed proposed Requirement R7 to have a Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator to notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators. This is a revision to existing EOP-002-3.1, Requirement R3. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language**

Summary Consideration: The EOP SDT drafted the language "as soon as practicable" to provide some priority to the notification from the Reliability Coordinator, but not to have this requirement exceed the priority of mitigating the emergency itself. Based on comments received, the EOP SDT has changed the word "practicable" to "practical."

Organization	Yes or No	Question 12 Comment
SPP Standards Review Group	No	We recommend including the Load Serving Entity in this requirement as follows: "Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator, Balancing Authority or Load Serving Entity shall notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators." We feel this is justified based on the statement in the first paragraph of the Introduction of Attachment 1, where the SDT points out that the Reliability Coordinator is responsible for communicating the 'condition' of Balancing Authorities or Load Serving Entities. However, the requirement doesn't include LSE. They need to be included. Additionally, we have some concern with the use of 'as soon as practicable'. We understand that this was inserted to stress the timeliness of this notification but have issues with its measurability. Some standards have used 'without intentional delay' in the past. While not a clear cut remedy, it does appear to be a little better and is consistent with other standards.
Northeast Power Coordinating Council	No	There should be a maximum time by which the RC must notify impacted parties; it cannot be left stated "as soon as practicable". Holding the RC responsible for this communication can be more streamlined and coordinated, but it adds time to

Organization	Yes or No	Question 12 Comment
		completion of the communication. Holding the individual entities whose area is experiencing an Emergency responsible for such notifications can speed up information dissemination, but may cause confusion. It must considered that an individual entity's top priority should be to resolve the Emergency.
Duke Energy	No	Duke Energy suggests the following revision to R7:"Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practicable, neighboring Reliability Coordinators and those Balancing Authorities and Transmission Operators within its Reliability Coordinator Area." We believe this change is necessary because the use of the word "impacted" is broad and subject to interpretation by an auditor. However, the RC should be required to notify neighboring RCs who can notify those BAs and TOPs within its RC area for determination on the impacts the Emergency could have on their respective systems. By notifying the TOPs and BAs within its RC area, it provides the situational awareness necessary to protect the reliability of the BES.
SERC OC Review Group	No	The SERC OC Regroup respectfully requests further guidance and clarification on the term "impacted". The concern centers on which entities would be considered "impacted". Current R7 language: Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators.
ACES Standards Collaborators	No	We request that the drafting team remove the language "as soon as practicable" from R7. This is ambiguous language, which cannot be measured and will only lead to confusion. We suggest replacing this clause with the word "other," so the requirement will state "...notify other impacted RCs, BAs, and TOPs." Otherwise, the requirement will literally require the RC to also notify the BA or TOP that just notified it.

Organization	Yes or No	Question 12 Comment
Hydro One	No	There should be a maximum time by which the RC must notify impacted parties; it cannot be left stating "as soon as practicable".
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration:1. Requirement R7 - ReliabilityFirst believes the term “as soon as practicable” 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.]”
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 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.
ISO/RTO Standards Review Committee	Yes	We are indifferent as to who should be responsible for providing notification of an Emergency from a TOP or BA within a RC Area to those entities that are impacted or could be impacted, as long as this is performed by a responsible entity. In deciding who should be responsible, the SDT should consider that, while holding the RC responsible for this notification is more streamlined and coordinated, it requires additional time to complete the notification. On the other hand, holding the

Organization	Yes or No	Question 12 Comment
		individual entity whose area is experiencing an Emergency responsible for such notifications can speed up information dissemination, but may lack information that could have been included in a report provided by an RC, with its oversight and wider-area view.
Independent Electricity System Operator	Yes	We are indifferent as to who should be responsible for communication Emergency in a TOP or BA within a RC Area to those entities that are impacted or could be impacted, for so long as this is performed by a responsible entity. Holding the RC responsible for this communication is more streamlined and coordinated, but it adds time to complete the communication. Holding the individual entities whose area is experiencing Emergency can speed up information dissemination, but may cause confusions.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 12 Comment
Bonneville Power Administration	Yes	
Idaho Power Company	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	
American Transmission Company, LLC	Yes	
CenterPoint Energy	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Lincoln Electric System	Yes	
City of Austin dba Austin Energy	Yes	

13. The EOP SDT has revised EOP-002-3.1, Requirement R6, Part 6.5 and Requirement R7, Part 7.2 and included it in EOP-011-1 as Requirement R8. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: The EOP SDT intentionally added the Attachment 1 to the EOP-011-1 by its inclusion into Requirement R2 Part 2.3. and Requirement R5; making Attachment 1 applicable to Reliability Coordinator's and Balancing Authorities, but not Transmission Operators. The EOP SDT has been working in a collaborative effort with the BAL SDT, but in no way was it ever the intention of the EOP SDT to allow the Balancing Authority to not meet its CPS and DCS requirements.

Organization	Yes or No	Question 13 Comment
MRO NERC Standards Review Forum	No	R8 is based on the entity having time to perform the steps in the Emergency Operating Plan. As we know system conditions can change so fast that the entity's involved may have to skip steps in their plan to mitigate the emergency. Recommend R8 to read; The BA shall request its RC to declare a NERC EEA after the BA has EITHER performed the steps in its Emergency Operating Plan OR is unable to resolve the capacity or Energy Emergency condition.
Dominion	No	Dominion believes R8 should be included as a sub-requirement in R2, we do not believe it qualifies as a standalone requirement.
SPP Standards Review Group	No	Although we agree with the concept, the language of Requirement R8 implies that the Balancing Authority only requests an EEA after it has completed the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. Coordination between the Plan and Attachment 1 is an issue. EEA Alert 1 is to be issued when the Energy Deficient Entity foresees the need to declare an Energy Emergency.

Organization	Yes or No	Question 13 Comment
		Alert 2 is issued when all available resources are in use. Alert 3 is issued when load management procedures are in effect. Alert 4 is issued when firm Load interruption is imminent or in progress. If an entity must first complete the steps in its Emergency Operating Plan (which must include manual Load shedding per R2) and is unable to resolve the capacity or Energy Emergency condition, the first three Alert Levels would have already been past. We suggest incorporating a new Part under Requirement R2.2 that requires the Balancing Authority requesting its Reliability Coordinator to declare Emergency Alert Levels satisfy the criteria for issuing an Energy Emergency Alert as outlined in Attachment 1. There are different Energy Emergency Alert Levels and they are issued at various stages within the event. The Balancing Authority's Emergency Operating Plan should include requesting the Reliability Coordinator to declare each level when conditions have been met for each level. This would eliminate the need for Requirement R8 and yet provide for the notification of the Reliability Coordinator and other impacted entities of the Emergency condition. The new Part 2.3.0 would read: "Utilization of Energy Emergency Alerts as detailed in Attachment 1." R8 could then be deleted.
Duke Energy	No	Duke Energy believes the proposed language for R8 could be interpreted to mean that all the steps in the entity's Emergency Operating Plan have to be performed before requesting the RC to declare an EEA. Our belief is that the entity's plan should include the steps taken for each EEA level that leads up to the entity making a determination to declare an EEA by making a request to the RC. We propose the following language for R8:"R8. Each Balancing Authority shall request its Reliability Coordinator to declare the appropriate NERC Energy Emergency Alert level, according to the Balancing Authority's Emergency Operating Plan, when the Balancing Authority is unable to resolve the potential or actual capacity or Energy Emergency condition. "We believe the proposed modification clarifies that not all the

Organization	Yes or No	Question 13 Comment
		steps in an entity's Emergency Operating Plan has to be performed before declaring and EEA.
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	There is no progressive severity associated with the words in R8 that reflect the multiple levels of an energy emergency condition outlined in Attachment 1. As written R8 seems to indicate that an Energy Emergency Alert is not initiated until all steps of an Emergency Operating Plan are exhausted. Southern also believes that the SDT, either in the Requirement or Attachment, should take the opportunity to clarify that it is not necessary to explicitly call for manual load shedding to return ACE to zero or to restore generation operating reserves under the new Energy Emergency Alert Level 4 unless to not do so creates a risk to the Interconnection.
SERC OC Review Group	No	The SERC OC Review Group recommends two changes to R8. The first is to add the term "appropriate" to the requirement and the second recommendation is to move R8 to R2 as a new Part 2.4 and eliminate R8.Current R8 language: The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. Proposed R8 language: The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. Proposed R8 language moved to a new R2, new Part 2.4: The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. This move to R2, new Part 2.4 will permit deleting R8. If the SDT accepts the R8 change then M8 will also require

Organization	Yes or No	Question 13 Comment
		inserting the term “appropriate” into the measure to be consistent with R8. Current R8 language: Each Balancing Authority who, after performing the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8.Propose M8 language: Each Balancing Authority who, after performing the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8.If the EOP SDT accepts moving R8 to a new R2, Part 2.4 then the team recommends the following to the M2:Current M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R2.Proposed M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2. In the case where each Balancing Authority who, after performing the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability

Organization	Yes or No	Question 13 Comment
		Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8.
ACES Standards Collaborators	No	The Emergency Operating Plan should not have to be exhausted to notify the RC of an EEA. Part of the Emergency Operating Plan should be when to notify other entities that will be impacted, including when to request an EEA from the RC. It is better for reliability to have the BA communicating with the RC if the BA anticipates a deficiency, rather than requiring the BA to exhaust all steps first. Furthermore, this requirement actually conflicts with the requirements to have Emergency Operating Plans in R1 and R2 because it requires these Emergency Operating Plans to be fully implemented. This would include manual load shedding in Part 2.2.8. Per the requirements in Attachment 1, an EEA3 should be issued when load management has been issued but it can't without violating R8 because the Emergency Operating Plan steps have not been fully exhausted. We recommend removing R8 from the standard and incorporating the notification into R1 and R2.
DTE Electric	No	Requesting the RC to declare a NERC EEA should be an integral part of a BA's plan. As written, "..after the Balancing Authority has performed the steps in its Emergency Operating Plan..." implies the entire BA plan has to be executed prior to requesting an EEA level. This can be interpreted as the BA must get all the way to manual load shed before requesting "Alert 1 - Forecast the need for an Energy Emergency". This comment is complementary to the suggestion in comment 5 regarding inclusion of EEA levels in the Emergency Operating Plan. Suggest rewriting R8 as follows: "The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert when conditions warrant in accordance with the Balancing Authority's Emergency Operating Plan."

Organization	Yes or No	Question 13 Comment
Xcel Energy	No	No, as proposed, the emergency plan will include a process to include manual load shedding. As written, R8 says that the BA can only ask for the RC to declare an EEA after it has completed the steps in the plan. So the BA must cut interrupt loads before the RC can declare an emergency. That should not be the intent of the standard. Additionally, R8 appears to conflict with R9. R8 tells the BA to request that the RC declare an emergency only after it has completed the steps in its plan. R9 tells the RC to declare an emergency if the BA or LSE is either experiencing an emergency or a potential emergency. So the RC must declare an emergency when the BA is potentially experiencing the emergency, but the BA can only request the RC declare after all steps of the plan have been completed. By the time the BA has completed the steps in its plan, the RC must have acted under R9. Requirment R8 should be removed from the proposed standard. The BA already has an obligation to notify the RC under R7 that it is experiencing trouble. There is no need to have the BA call back to request that the RC do something that the RC can do on its own and is required to do under the proposed R9.
Electric Reliability Council of Texas, Inc.	No	The inclusion of "NERC" before Energy Emergency Alert is unnecessary and could be problematic potentially from a compliance point of view. EEA is a qualitative term under the NERC standards. The specific system conditions that define EEAs are determined by the relevant regional operational rules. Referring to an EEA as a NERC EEA could be interpreted as implying there is a NERC standard for triggering EEA conditions, which is not true. To mitigate the potential for introducing this ambiguity, the word "NERC" should not be used in conjunction with EEA. Although ERCOT appreciates the intent of R8, the practical implications of the sequence of actions reflected in the standard could be problematic in practice. For example, in ERCOT, where ERCOT is the sole BA and RC, emergency operating plans are used to address EEA events. Yet, under R8 it is contemplated that the BA

Organization	Yes or No	Question 13 Comment
		would exhaust its emergency operating options prior to the declaration of an EEA. This creates a practical disconnect in ERCOT because at that point ERCOT would have been in an EEA situation and executed its relevant emergency procedures. In addition, R8 is problematic due to the removal of the CPS and DCS criteria as part of the original requirement, which were included to highlight the area imbalance and the circumstances where an LSE or BA was imbalanced and leaning on its neighbors to an unacceptable degree. In those circumstances the BA/LSE was required to exercise all available options, , up to and including firm load shed to help protect the interconnection. While the requirements are still similar in nature, some of the sub-requirements are not captured in R2, such as deploying all available operating reserve or requesting emergency assistance.
Public Service Enterprise Group	Yes	R8 should reference Attachment 1 - EOP-011. It should be modified to say The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert [ADD: per Attachment 1-EOP-011-1]....
City of Tallahassee	Yes	While TAL supports the proposed requirement, we maintain that more clarity is needed regarding “the steps in its Emergency Operating Plan”. TAL recommends changing the language to include “appropriate steps” or “necessary steps”. It is not necessary for all steps in the plan be completed prior to requesting an EEA. This should be allowed.
Arizona Public Service Company	Yes	
Florida Municipal Power Agency	Yes	
Northeast Power Coordinating Council	Yes	
ISO/RTO Standards Review Committee	Yes	

Organization	Yes or No	Question 13 Comment
Florida Power & Light	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
Lincoln Electric System	Yes	
City of Austin dba Austin Energy	Yes	

14. The EOP SDT has revised EOP-002-3.1, Requirement R8 and included it in EOP-011-1 as Requirement R9. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: After consideration of comments received, the EOP SDT has removed the Load-Serving Entity. Also in response to comments, the EOP SDT has removed "NERC" from in front of "Energy Emergency alert."

Organization	Yes or No	Question 14 Comment
MRO NERC Standards Review Forum	No	Since LSE is included in R9, it will need to be added throughout the Standard, where applicable.
Dominion	No	Dominion suggests that Load-Serving Entity be removed from this requirement. If the SDT wants to require that a LSE experiencing a potential or actual Energy Emergency notify an entity, that entity should be its BA (therefore suggest this be included as a sub-requirement to R2). Dominion does not believe that such a requirement or sub-requirement is necessary and would suggest that this decision be left to each BA.
SPP Standards Review Group	No	Delete 'NERC' in the last line of the Requirement. Change 'experiencing' to 'experience' in the 2nd line of M9. Also delete 'NERC' in the next to last line of M9.
Xcel Energy	No	The answer to this question is dependent upon how the drafting team addresses the conflict between R8 and R9 identified in question 13 above.
Public Service Enterprise Group	No	LSEs should not be subject to the standard since their BAs are subject to it. R9 should be modified to eliminate phrase "a Load Serving Entity." See our response in question 17, paragraph 2, which provides additional justification for this deletion.
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration:1. Requirement R9 - ReliabilityFirst believes there should a timeframe associated with how long a

Organization	Yes or No	Question 14 Comment
		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.]”
ACES Standards Collaborators	Yes	We thank the drafting team for clarifying that the Load Serving Entity is not applicable. We would like to see this language in an RSAW.
Arizona Public Service Company	Yes	
Florida Municipal Power Agency	Yes	
Northeast Power Coordinating Council	Yes	
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 14 Comment
Generation and Energy Marketing		
SERC OC Review Group	Yes	
DTE Electric	Yes	
ISO/RTO Standards Review Committee	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
American Electric Power	Yes	
Hydro One	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 14 Comment
CenterPoint Energy	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Lincoln Electric System	Yes	
City of Austin dba Austin Energy	Yes	

15. The EOP SDT has revised Attachment 1 of EOP-002-3.1. Do you support the proposed revisions to Attachment 1? If not, please provide specific suggestions for improvement

Summary Consideration: The EOP SDT has restored the previous three alert levels of Attachment 1 in response to industry comments received. Attachment 1 has been through an additional revision subsequent to the informal comment period due to (1) industry comments received and (2) in a collaborative effort with the standard drafting team for BAL-002. The revisions are mapped within the Project 2009-03 Emergency Operations EOP-011-1 Mapping Document, as well.

Organization	Yes or No	Question 15 Comment
Dominion	No	Dominion believes the reporting hierarchy should be preserved so that only BA and TOP communicate with the RC. Entities that may be, or are, energy deficient (LSE) should have to communicate that information to their BA. The BA's Emergency Operating Plan (R2) should include one or more steps to request its Reliability Coordinator to declare a NERC Energy Emergency Alert as necessary (there are 3 levels, we think there probably needs to be multiple steps and a request at each level).
SPP Standards Review Group	No	We suggest the last line of the 1st paragraph of the Introduction be modified to read 'Entity within its Reliability Coordinator Area which is experiencing an Energy Emergency.' Change three levels to four levels in the Introduction under Section B. Energy Emergency Alert Levels. In the 2nd bullet under Circumstances in Section 3. Alert 3 - ..., change 'implemented' to 'activated.' Modify Section 3.4 to read 'If Transmission limitations are contributing to the Energy Emergency, the Reliability Coordinator should review Transmission outages and work with the applicable Transmission Operator to see if it's possible to return to service the Transmission element(s) that could relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).'Modify Section 3.5.2 to read 'Initiate curtailment of contractually interruptible Loads and activate demand-side management. Initiate curtailment of contractually interruptible retail Loads and activate demand-side management within provisions of the agreements.' Modify the

Organization	Yes or No	Question 15 Comment
		2nd and 3rd sentences in Section 4.3 to read 'Reevaluation of SOLs and IROLs should be coordinated with other impacted Reliability Coordinators and only after agreement has been reached with the Balancing Authority(ies) or Transmission Operator(s) whose equipment would be affected. SOLs and IROLs should only be revised as long as an Alert 4 condition exists, or as allowed by the Balancing Authority(ies) or Transmission Operator(s) whose equipment is at risk. Modify Alert 0 - Termination. to read 'When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it should request its Reliability Coordinator to terminate the EEA.
Northeast Power Coordinating Council	No	While the initial Attachment 1 is largely intact, we notice that the notification details under an Alert 2 have been removed. The mapping document does not provide the rationale for the removal, nor is it presented in any of the technical justification document. We see the need for having such details in the revised Attachment 1, but are not provided the basis of the removal to aid an assessment. Please provide the rationale.
Duke Energy	No	See comments on 16. If the decision is made to move this to the NERC Glossary of Terms and a Guidance Document, Duke Energy will do a thorough review of Attachment 1 and provide necessary comments.
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	No	Southern prefers the previous three levels in the current Attachment 1 and sees only minimum advantages to the addition of the fourth level. Southern does believe that some of the clarifications in the new Attachment of the existing wording is an improvement. If the SDT chooses to keep the 4 levels then we have the following comments: Alert Level 2 refers to "available resources" - Does that include demand side resources or just generation? Does the SDT believe that demand side options are prohibited from being used unless an Alert Level 3 is declared? This needs to be clarified based on the heading of Alert Level 3. Item 3.5.3 refers to Emergency Assistance through an operating reserve sharing program. Not all BAs have Operating Reserve Sharing programs and not all emergency assistance is obtained

Organization	Yes or No	Question 15 Comment
Generation and Energy Marketing		through operating reserve sharing programs. The new EOP-011 has lost the concept of BAs requesting emergency assistance directly from other Bas without the use of a reserve Sharing Agreement. Seeking emergency assistance through RC coordination efforts needs to be emphasized since it often may be the primary mechanism for restoring reserves and avoiding manual load shed.
SERC OC Review Group	No	The SERC OC Review Team requests clarification on 1. Alert 1 - Forecast the need for an Energy Emergency. Circumstances: o Energy Deficient Entity foresees the need to issue alerts in the upcoming operating window and is concerned about Operating Reserves.The specific concern centers on what is meant by the phrase “upcoming operating window”. As written each entity could select a different “upcoming operating window”.
DTE Electric	No	In the second line of the Introduction of section B, change “NERC has established three levels...” to “NERC has established four levels...” Alert 1: The purpose of Alert 1 is an Energy Deficient Entity is projecting to move into Alert 2, 3, or 4. Operating Reserves are addressed in Alert 2 and 3 so do not need to be mentioned in Alert 1. Consider changing Alert 1 Circumstances to the following: “Energy Deficient Entity foresees the need to request the Reliability Coordinator issue Alerts 2, 3, or 4 in the upcoming operating window.” Alert 3 Circumstances: The second bullet has vague language “...implemented its approved Emergency Operations Plan”, it does not specify what steps have been implemented. Since alert 3 is supposed to address “Load management procedures in effect”, consider adding examples of Load management to this bullet. NERC EOP-002-3.1 alert 2 bulleted list adequately describes Load management: Public appeals to reduce demand. Voltage reduction. Interruption of non-firm end use loads in accordance with applicable contracts Demand-side management. Utility load conservation measures.
ISO/RTO Standards Review Committee	No	While the initial Attachment 1 is largely intact, we notice that the notification details under an Alert 2 have been removed. The mapping document does not provide the rationale for the removal, nor is it presented in any of the technical justification

Organization	Yes or No	Question 15 Comment
		documents. While we believe that there is a need to keep such details in the revised Attachment 1, we have not been provided the basis of the removal to aid an assessment. Please provide the rationale.
Florida Power & Light	No	Current attachment 1 is adequate and adding an additional alert does not add value as forecasted conditions are covered under the existing attachment.
City of Garland	No	Concern - Do not see a benefit to BES reliability or security from revising the Alert levels that would justify the large amount of administrative man-hours that would have to be expended at both the ISO level and at the Registered Entity level. In ERCOT and probably other ISOs, the ISO utilizes Protocols and Operating Guides to operate the various functions of the electric system. Both of these will have to be revised as they both currently reflect the current Alert levels in EOP-002 Attachment 1. Registered Entities also have procedures detailing that Entity's course of action when a RC issues a certain Alert level which would have to be rewritten. Additionally, anyone who has anything to do with electric system operations knows what the current Alert levels are, what they mean, and what actions are to be taken. If the Alert levels are changed, then everyone has to be retrained. Recommendation: Leave the current Alert levels the same. ERCOT has 3 pre-alert notifications based on actual or projected system conditions (Operating Condition Notices, Emergency Advisories, and Emergency Watches) - all designed to communicate prior to reaching the first Alert level that there are concerns about a potential energy deficiency. I have to believe that other ISOs have similar pre-alert notifications though the naming conventions probably vary.
Idaho Power Company	No	No need to create an Alert 4 category. The existing alerts 0-3 seem to be adequate.
Xcel Energy	No	The drafting team needs to modify the attachment further. The attachment should use defined terms or periods in order to ensure clarity. As an example, what is the "operating window" used under the Alert 1 section? Is it the next hour, next day, or

Organization	Yes or No	Question 15 Comment
		next week? The attachment must provide clarity if it is to be included with the standard.
Independent Electricity System Operator	No	While the initial Attachment 1 is largely intact, we notice that the notification details under an Alert 2 have been removed. The mapping document does not provide the rationale for the removal, nor is it presented in any of the technical justification document. We see the need for having such details in the revised Attachment 1, but are not provided the basis of the removal to aid an assessment. Please provide the rationale.
Public Service Enterprise Group	No	We recommend the following changes to Attachment 1-EOP-011-1:1. Consistent with our request in paragraph 2.a. in question 17 below to remove LSE from the definition of Energy Alert, please delete “Load-Serving Entity” from first paragraph and also the second paragraph that defines an “Energy Deficient Entity.”2. Combine Alert 2 and Alert 3 into one single Alert 2. Demand response resources are a part of a BA’s total resources that includes generation resources. Alert 2 now says “All available resources in use” which is not factually correct unless demand response resources are included. Alert 2 is proposed to be changed as shown below. (For the SDT’s information, the phrase “controllable and dispatchable Demand Side Management Load” used below is taken from the definitions of “Demand Side Management” and “Total Internal Demand” in MOD-031-1 that is under development in Project 2010-04 Demand Data (MOD C).) SUMMARY OF PROPOSED CHANGES TO ALERT 22. Alert 2 - All [ADD:forecasted] available resources (generation and controllable and dispatchable Demand Side Management Load) are committed [ADD: and interruption of Firm Demand is imminent].Circumstances: o Energy Deficient Entity is experiencing conditions where all available resources (generation and controllable and dispatchable Demand Side Management Load) are committed to meet [STRIKE:firm Load][ADD: Firm Demand], firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves. o (Deleted the first bullet under Alert 3.) o Energy Deficient Entity has implemented its approved Emergency Operations Plan. During Alert 32, Reliability Coordinators, Balancing

Organization	Yes or No	Question 15 Comment
		Authorities and Energy Deficient Entities have the following responsibilities: OTHER CHANGES: Change the “3” in 3.1 through 3.5 to “2” so that “3.1” becomes “2.1, etc.” Make similar changes to 3.5.1 through 3.5.3. In addition, change the language in existing 3.5.2 as follows[STRIKE:3][ADD:2].5.2 Initiate [STRIKE: contractually interruptible Loads and demand-side management curtailed][ADD:interruption of controllable and dispatchable Demand Side Management Load.] Initiate [STRIKE: contractually interruptible retail Loads curtailed, and demand-side management activated][ADD:interruption of non-Firm Demand] within provisions of their agreements.3. Make these changes to Alert 4 follows: SUMMARY OF PROPOSED CHANGES TO ALERT 4[ADD:3.] Alert [STRIKE:4][ADD:3] - [ADD:Firm Demand][STRIKE:Load] interruption [STRIKE: imminent or] in progress.OTHER CHANGES: Change the first bullet to “Energy Deficient Entity” [STRIKE: foresees or] has implemented interruption of [ADD:Firm Demand][STRIKE:firm Load obligation interruption]. Change the “4” in 4.1 through 4.4 to “3” so that “4.1” becomes “3.1,” etc.” Also change “4.4.1” to “3.4.1.” In existing 4.1, change “Alert 4” to “Alert 3” in two places.
Manitoba Hydro	No	(1) Attachment 1: This Attachment states that “NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements and nothing in these procedures should be interpreted as changing those obligations.” This provision is both unclear and problematic for Canadian registered entities. First, the reference to “FERC-approved tariffs and other agreements” is inappropriate. Canadian tariffs are not regulated or approved by FERC, unless the Canadian entity has market-based rate authorization from FERC. In some cases tariffs are approved by Canadian regulators and in other jurisdictions they are authorized under provincial law. Furthermore, most Canadian energy sale agreements are either not approved by a regulator or only approved to the extent that they involve an international export. More importantly, if this clause in the attachment was intended to state that the standard does not override tariffs and agreements in the event of a conflict, then such wording would not be legally effective in Canada where a single regulator does not perform the function of approving Canadian tariffs, energy sale

Organization	Yes or No	Question 15 Comment
		agreements and NERC standards, thereby having the power to reconcile conflicts. In Canada this would be a matter of statutory provisions on point and may vary from province to province. Legislation governing NERC standards may take precedence over contracts and tariffs. Therefore, this provision should be deleted
Tacoma Power	No	Stating there are “three” levels of Energy Emergency Alerts, when there are actually “five” (including Level 0) is a constant source of confusion amongst trainees and junior Operators. In many regions, these standards are something that the Operator only works with during training classes, so we need to remove any confusion where possible. Please fix this.
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) requests clarification on the changes to Attachment 1 and the justification for those changes. Renumbering the EEA levels (and adding an additional level) could potentially create confusion; the benefit of any changes would need to offset their cost.
ACES Standards Collaborators	Yes	Adding an additional alert level to the attachment is confusing, especially when Alert 4 requires the entity to continue actions it was doing in Alert 3. We strongly suggest revising this document to have bright line differences between each alert level. Was there a reliability need to modify the prior attachment? Were a majority of registered entities having issues with the concepts of the EEA process?
Oncor Electric Delivery Company LLC	Yes	Oncor Electric Delivery (Oncor) supports the revisions to Attachment 1 in the proposed EOP-011-1; however, Oncor cautions the separation of Energy Emergency Alert (EEA) 2 into two separate EEAs (2 and 3) since it would require a great deal of administrative revision and could limit flexibility to existing Procedures for all entities involved, with no reliability benefit from the separation. Oncor appreciates another look at this revision by the SDT. Additionally, for clarifying purposes, Oncor recommends that Responsibility 3.4 under Alert 3 in Attachment 1 should include the following changes:3.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator should review Transmission outages and work with the

Organization	Yes or No	Question 15 Comment
		Transmission Operator to see if it's possible to return the Transmission element <back to service> that may <return the system to pre-emergency conditions or> relieve the Loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Florida Municipal Power Agency	Yes	
Hydro One	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Bonneville Power Administration		In the section on Alert 3 under Circumstances, BPA believes that the second bullet "Energy Deficient Entity has implemented its approved Emergency Operations Plan" should be removed because Load Serving Entities are included in the definition of Energy Deficient Entities but they do not have "approved Emergency Operations Plans" so this cannot happen when the EDE is an LSE. Also, looking at R2, a BA would be exercising their Plan at least by Alert level 1 so of course they would have

Organization	Yes or No	Question 15 Comment
		implemented it by EEA 3. That bullet is not necessary and is in direct conflict with the fact that LSE's aren't required to have plans under this standard.
Consumers Energy Company		N/A to SC&M Department

16. **The EOP SDT has considered technical justification to remove Attachment 1 from the proposed EOP-011-1. If Attachment 1 were to be removed, the SDT proposes that NERC's Energy Emergency Alert levels be incorporated into the NERC Glossary as defined terms, with some of the additional information in Attachment 1 incorporated as a guidance document. Would you support this approach? If not, please provide specific suggestions for an alternate approach that you would support.**

Summary Consideration: The EOP SDT appreciates your comments. Being this was closely a split issue, the EOP SDT has made the decision to retain Attachment 1 with EOP-011-1. The EOP SDT has restored the previous alert levels of Attachment 1 in response to industry comments received. Attachment 1 has been through an additional revision subsequent to the informal comment period due to (1) industry comments received and (2) in a collaborative effort with the standard drafting team for BAL-002.

Please note that there are several references in the documents to (3) three Energy Emergency alert levels (currently-enforce Attachment 1 from EOP-002.3.1). Through comments, it has been pointed out to the EOP SDT that there are, in fact, (4) four Energy Emergency alert levels: 0 – 3; that Alert 0 – Termination is one of (4) four alert levels. The EOP SDT, when making future reference within documents, will reference (4) four alert levels.

Organization	Yes or No	Question 16 Comment
SPP Standards Review Group	No	Unless there is a pressing need to remove the Attachment, we recommend leaving it where it is. This is a known document with many years of use in the industry. We're familiar with it and know how to use it. The SDT hasn't really provided any justification for moving it to the Glossary and unless the SDT can help us understand why we need to make the change, we can't support it. We also have concerns with how the Attachment would be logistically moved into the Glossary. It appears that only part of the document would go into the Glossary and the remaining material would be retained in a guidance document. Splitting the material would degrade the value of the document as it currently exists.
Florida Municipal Power Agency	No	FMPA would prefer to retain it as an attachment to the standard.

Organization	Yes or No	Question 16 Comment
Northeast Power Coordinating Council	No	Both the proposed and current approaches are acceptable. We can support defining the EEA levels through a definition, and incorporate them into the NERC Glossary. However, Attachment 1 also serves the purpose of providing necessary information associated with and required for issuing EEAs. To put some of that into the Glossary of Terms, will make the defined term very lengthy. Putting other information into a guideline document is only possible if none of the required information depicted in Attachment 1 is mandatory. Unfortunately, we are unable to locate the detailed technical justification the EOP SDT used to support the proposed removal of all information in Attachment 1 that are "requirements". Please provide them at the next posting so that we can assess the merit of this proposal. A mapping of the detailed information in Attachment 1 after the proposed removal will be very helpful. The following should be added to the Glossary of Terms as defined terms:" Energy Emergency Alert" "Energy Deficient Entity" Additional comment on Attachment 1, Alert 3 and Alert 0: Shouldn't the words here match the words used in the revised definition of "Energy Emergency" so as to say "is no longer able to meet Load?" (same as under "Alert 0")?
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	The SDT needs to provide additional guidance on the compliance implications of leaving it as an Attachment or implementing the proposal of the Attachment being incorporated into the NERC Glossary of defined terms. For example, does an Attachment to a standard imply any more compliance obligation than the same words in a guidance document?

Organization	Yes or No	Question 16 Comment
DTE Electric	No	Suggest leaving the content in Attachment 1. Moving EEA levels to the glossary and a separate guidance document will unnecessarily complicate the language of R9. As written, R9 is clear and concise.
ISO/RTO Standards Review Committee	No	While we could support defining the EEA levels through a definition, and incorporating them into the NERC Glossary, Attachment 1 also serves the purpose of providing necessary information associated with and required for issuing EEAs. Including part of that information into the Glossary of Terms will make the defined term very lengthy. In addition, moving other information to a guideline document is only possible if the information currently included in Attachment 1 is not mandatory. Unfortunately, we cannot locate the detailed technical justification the EOP SDT used to support the proposed removal of all information in Attachment 1 that are “requirements.” Please provide it with the next posting so that we can assess the merit of this proposal. A mapping of the detailed information in Attachment 1 after the proposed removal will be very helpful. While we do not support defining EEA levels as proposed, we do have the following comments regarding the proposed definition for Energy Emergency and suggestion for defining the three terms and adding them to the NERC Glossary as appropriate: In the revised definition of Energy Emergency the word “energy" has been replaced with "Load". The revised definition now seems to imply that reserves have been exhausted and a BA simply can't serve load. On the other hand, the word “energy” implies that planned dispatch has been used up and a BA must now begin to utilize reserves, which we believe is more aligned with the EEA steps. We suggest restoring the word “energy”. Further, we suggest replacing “provide” with “meet”. The revised definition will thus read: Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer meet its customers’ expected energy requirements. We propose to define the following three terms: “Energy Emergency Alert” “Energy Deficient Entity” Emergency Operating Plans” The term Energy Emergency Alert is referenced in the standard and in Attachment 1, and is capitalized. But this term is not defined in the NERC Glossary. Similarly, the term Energy Deficient

Organization	Yes or No	Question 16 Comment
		Entity is referenced in Attachment 1 and is capitalized, but it is not defined in the NERC Glossary. Likewise, the term Emergency Operating Plan is referenced in the standard and is capitalized, but it is not defined in the NERC Glossary. These terms need to be put in lower case, or defined for use in this standard only, or defined and included in the Glossary. Additional comment on Attachment 1, Alert 3 and Alert 0: the language here should match the language used in the revised definition of “Energy Emergency” (including our proposed edits) so as to say “can no longer meet its expected energy Load.” (Same comment under “Alert 0”).
Florida Power & Light	No	Current Attachment 1 provides the details needed to meet the requirements.
Independent Electricity System Operator	No	We can support defining the EEA levels through a definition, and incorporate them into the NERC Glossary. However, Attachment 1 also serves the purpose of providing necessary information associated with and required for issuing EEAs. To put some of that into the glossary of term, it will make the defined term very lengthy. And putting other information into a guideline document is only possible if none of the required information depicted in Attachment 1 is mandatory. Unfortunately, we are unable to locate the detailed technical justification the EOP SDT used to support the proposed removal of all information in Attachment 1 that are “requirements”. Please provide them at the next posting so that we can assess the merit of this proposal. A mapping of the detailed information in Attachment 1 after the proposed removal will be very helpful.
Public Service Enterprise Group	No	It is unclear how a new Glossary term for Energy Emergency Alert would be defined by the SDT and what would remain in Attachment 1 as guidance. We would need to see the proposed EEA definition and a revised Attachment 1.
CenterPoint Energy	No	CenterPoint Energy does not believe that Energy Emergency Alert levels should be codified in the NERC Glossary and does not support such an approach. The Company believes the NERC Glossary should be reserved for definitions of terms used throughout the Reliability Standards. Terms used in one or two Standards should be

Organization	Yes or No	Question 16 Comment
		defined in the Standard where the term is utilized. CenterPoint Energy recommends keeping Attachment 1 in the proposed EOP-011-1.
Lincoln Electric System	No	Recommend the Energy Emergency Alert levels remain within the document where they are used.
Oncor Electric Delivery Company LLC	No	Oncor prefers and supports the use of the revised Attachment 1 in proposed EOP-011-1, with the changes suggested in Question 15.
City of Austin dba Austin Energy	Yes	City of Austin dba Austin Energy (AE) could work with either format as long as any changes are identified and justified.
Duke Energy	Yes	Duke Energy agrees with this approach for the following reason. By moving Attachment 1 to the NERC Glossary of Terms and adding a Guidance Document, it provides subsequent SDTs the flexibility to amend the EEA levels as necessary within one Standards Development project without having to initiate multiple Standards Development projects simultaneously. This prevents the posting of projects for the sole purpose of modifying an Attachment to a Standard.
ACES Standards Collaborators	Yes	We could support the removal of attachment one, as long as the alert levels remain the same (zero through 3). If the drafting team is going to revise the alert levels as proposed in the current draft by including alert level 4, then it would be better to keep the attachment with the standard.
City of Garland	Yes	Agree with this but do not agree with revising Alert levels - see comments on question 15
Idaho Power Company	Yes	No need to create an Alert 4 category. The existing alerts 0-3 seem to be adequate.

Organization	Yes or No	Question 16 Comment
Xcel Energy	Yes	This could be preferential to the current attachment. Since the current attachment needs significant work, this process might address our concerns in a better way than the current proposal.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	

17. **Do you have any other comments regarding proposed EOP-011-1, not included above, that you would like to provide to the EOP SDT? If so, please provide specific comments for improvement**

Summary Consideration: The EOP SDT appreciates the many comments received. The EOP SDT has made several of the clarification edits suggested. With the proposal of a revision to a definition, the EOP SDT is obligated to list standards the term is used in. As stated in the standard, the EOP SDT does not believe the proposed revision changes the intent of the requirements or definitions. The EOP SDT is not suggesting any changes to the intent of the requirements in BAL-002-WECC-2, this standard was listed because the EOP SDT was obligated to do so, as the term is used in this standard. There were comments made regarding "Emergency Operating Plan," noting that together this is not a defined term. The intent of the EOP SDT is the defined term "Emergency" and the defined term "Operating Plan." The EOP SDT appreciates the time that is involved in reviewing the standard and the documents during the informal comment period. The comments received has provided the EOP SDT an opportunity to incorporate many of suggestions made in an effort to improve upon EOP-011-1 prior to posting for initial comment period and ballot.

Organization	Yes or No	Question 17 Comment
Arizona Public Service Company	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	No	

Organization	Yes or No	Question 17 Comment
Company Generation; Southern Company Generation and Energy Marketing		
SERC OC Review Group	No	The OC Review Group request further clarification on R1 and R2 minimum set of elements. There are cases where specific elements may be utilized for non-emergency reasons. For example, voltage reduction, load curtailable load and interruptible load can be utilized for non-emergency purposes. Would these activities constitute plan implementation? C. 1.1.2 Evidence Retention: If the EOP SDT accepts deleting R8 and creating a new R2, Part 2.4 then the evidence retention section would require modification. Current language: The Balancing Authority shall maintain evidence of compliance since the last audit for Requirements R6 and R8 and Measures M6 and M8.Proposed language: The Balancing Authority shall maintain evidence of compliance since the last audit for Requirements R2 and R6 and Measures M2 and M6.The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
DTE Electric	No	
Florida Power & Light	No	
PacifiCorp	No	
Bonneville Power Administration	No	
Consumers Energy Company	No	

Organization	Yes or No	Question 17 Comment
American Transmission Company, LLC	No	
Wisconsin Electric	No	
City of Tallahassee	No	
MRO NERC Standards Review Forum	Yes	We appreciate the efforts of the SDT and the FYRT to consiladiate the 3 existing standards from the EOP group into a single standard that is clearer and the requirements are organized by Functional Entity.
Dominion	Yes	M1 contains "that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator," this also needs to be included in M2.
SPP Standards Review Group	Yes	Background Section: In the 3rd line of the paragraph below the bullet points, spell out Bulk Electric System and then follow it with the BES in parentheses.
Florida Municipal Power Agency	Yes	FMPA appreciates the work of the SDT to vastly improve the standards.
Northeast Power Coordinating Council	Yes	In the section of the standard entitled "Definitions of Terms Used in Standard", the SDT has defined Energy Emergency as: "Energy Emergency - a Condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide expected Load requirements". This is a revision of the definition in the NERC Glossary is unclear because it does not define the point at which the Load-Serving Entity or Balancing Authority should decide that they can no longer provide expected Load requirements. Is that when it can no longer provide all necessary Load requirements? Or is it intended to mean that a significant portion of the Load requirements can no longer be provided - and if so, what constitutes a significant portion? More clarity is needed in the standard. Suggest revising the definition by

Organization	Yes or No	Question 17 Comment
		changing “provide” to “meet” and delete “requirements”. The proposed definition would then read “...can no longer meet its expected Load.” Even if it is preferable to not define the specific point in the standard, the standard should state that the Energy Emergency condition will be defined and documented by the Balancing Authority or the Load Serving Entity. Comments on BAL-002-WECC-2 - Contingency Reserve: We are unclear on the inclusion of “BAL-002-WECC-2 - Contingency Reserve” and Requirement R1 on P. 3, Definitions of Terms Used in Standard. Please clarify. Also, “energy emergency” is not capitalized in one of the R1.1 bullets here - it should be because it is a defined term.” Emergency Operating Plan” is capitalized but it is not a defined term in the Glossary of Terms and there is no definition included in this draft of the standard. A definition should be added or it should not be capitalized. Comment on R1 and R5: the standards talk about “operating Emergencies.” There are definitions for “Energy Emergency,” “Capacity Emergency,” and “Emergency” (or “BES Emergency”). If the definition of “Emergency” captures what is needed, then the word “operating” isn’t needed and should be deleted. The phrase “operating Emergency” also appears in R5.Comment on R2, R6, and R8: Energy Emergency has a definition in the draft - but what constitutes a “capacity” is not capitalized in “capacity Emergency.” The definition of “Capacity Emergency” in the Glossary is “[a] capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.” So, if this is what the standard means by “capacity Emergency,” then it should be capitalized. R2 should read: “to mitigate Capacity Emergencies and Energy Emergencies.” Same comment applies to R6 and R8.
Duke Energy	Yes	Duke Energy suggests replacing “requirements” with “obligations” in the definition of Energy Emergency. Our proposed definition is as follows: “Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its expected Load obligations.” We believe

Organization	Yes or No	Question 17 Comment
		obligated is a more appropriate term because LSEs or BAs are not required to serve load, rather they are obligated to do so.
ACES Standards Collaborators	Yes	(1) The VSL table is blank. We cannot support a standard that is incomplete and does not provide guidance on how enforcement will be interpreting this standard and translating violations into monetary penalties.(2) The guidelines and technical basis section is blank. We suggest waiting to post draft standards until they are complete.(3) Thank you for the opportunity to comment.
ISO/RTO Standards Review Committee	Yes	Requirement R8 requires a BA to request its RC to declare EEA when necessary. R9 requires the RC to initiate an EEA when its BA or LSE is experiencing a potential or actual Energy Emergency. It implies that a RC needs to be watching the conditions in its area, and initiate the EEA as needed. However, such a process could also be initiated by a BA's request under R8. If R9 is retained as written, then R8 could be removed, and a new requirement be added to require the RC to monitor the energy conditions in its area to detect potential or actual Energy Emergency of its BAs and LSEs. If R8 is retained, then we suggest that a new requirement be added to require the RC to monitor the energy situation as indicated above, plus revise R9 as follows: R9. Each Reliability Coordinator that receives notification from a Balancing Authority that is is unable to resolve a capacity or Energy Emergency condition or that assesses that a Balancing Authority or Load-Serving Entity is experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1. Comments on BAL-002-WECC-2 - Contingency Reserve: We are unclear on the inclusion of "BAL-002-WECC-2 - Contingency Reserve" and Requirement R1 on P. 3, Definitions of Terms Used in Standard. Please clarify. Also, "energy emergency" is not capitalized in one of the R1.1 bullets here - it should be because it is a defined term. Global Comment: "Emergency Operating Plan" is capitalized but it is not a defined term in the Glossary of Terms and there is no definition included in this draft of the standard. A definition should be added or it should not be capitalized. Comment on R1 and R5: the standards talk about "operating Emergencies." There are definitions for "Energy

Organization	Yes or No	Question 17 Comment
		Emergency," "Capacity Emergency," and "Emergency" (or "BES Emergency"). If the definition of "Emergency" captures what is needed, then the word "operating" should be deleted. The phrase "operating Emergency" also appears in R5.Comment on R2, R6, and R8: Energy Emergency has a definition in the draft - but "capacity" is not capitalized in "capacity Emergency." The definition of "Capacity Emergency" in the Glossary is "[a] capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements." So, if this is what the standard means by "capacity Emergency," then it should be capitalized. R2 should read: "to mitigate Capacity Emergencies and Energy Emergencies." Same issue in R6 and R8.
Hydro One	Yes	In the section of the standard entitled "Definitions of Terms Used in Standard", the SDT has defined Energy Emergency as: "Energy Emergency - a Condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its customers' expected energy Load requirements". This definition is also in the NERC Glossary. This statement is unclear because it does not define the point at which the Load-Serving Entity or Balancing Authority should decide that they can no longer provide expected Load requirements. Is that when they can no longer provide all necessary Load requirements? Or is it intended to mean that a significant portion of the Load requirements can no longer be provided - and if so, what constitutes a significant portion? More clarity is needed in the standard. Even if it is preferable not to define the specific point in the standard, the standard should state that the Energy Emergency condition will be defined and documented by the Balancing Authority or the Load Serving Entity.
Idaho Power Company	Yes	When Capacity Emergencies are mentioned they are not capitalized, it is a NERC defined term. Example: R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate

Organization	Yes or No	Question 17 Comment
		capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include
Xcel Energy	Yes	Xcel Energy appreciates the efforts of the drafting team to date and believes the consolidation of standards is an improvement. The drafting team has addressed many of the issues currently identified with the existing standards. We look forward to additional improvements in the next revision of the draft standard.
Independent Electricity System Operator	Yes	We are unclear on the inclusion of “BAL-002-WECC-2 - Contingency Reserve” and Requirement R1 on P. 3, Definitions of Terms Used in Standard. Please clarify.
Public Service Enterprise Group	Yes	1. The Emergency Operating Plans developed under R1 and R2 may contain Critical Energy Infrastructure Information (CEII). There should be a requirement that if such plans contain CEEI, (a new term that would need to be defined in the NERC Glossary but which FERC has defined) such information should be redacted before making the plans available in a public domain. Furthermore, such plans should be maintained by entities in a manner consistent with the treatment of CEII.2. We recommend two changes in the definition of Energy Emergency: a. Eliminate the reference to Load-Serving Entity and just reference Balancing Authority. The LSE’s BA should, through R9, be the lowest level entity that experiences an Energy Emergency. A BA that dispatches for several LSEs may be able to resolve an LSE energy emergency issue, and if it cannot, the BA should act under R9. See our response to question 14 that also recommended deletion of Load Serving Entity from R9.b. A NERC Glossary term is already defined for “Firm Demand.” We therefore recommend that “Firm Demand” replace “Load.” There is no Energy Emergency when a BA expects to interrupt non-Firm Load. With these changes, “Energy Emergency” would be defined as “A condition when a Balancing Authority has exhausted all other options and can no longer provide its customers’ expected Firm Demand requirements.”
Ingleside Cogeneration LP	Yes	As a GO/GOP, ICLP would like to reinforce the project team’s decision to defer work on generator-related extreme weather preparedness. The issue has been fully vetted

Organization	Yes or No	Question 17 Comment
		under other project headings - and will be actively re-reviewed in the gas/electricity interdependency initiative that FERC is driving. Furthermore, the local regulatory authorities are aggressively taking the lead on winterization planning. In our specific case, the Texas PUC has already required that we submit detailed winterization plans for a quality assessment - and any addition to the EOP requirements would just increase our administrative overhead. We are aware that the priority on this topic may change as a result of the series of winter storms that North America experienced earlier this year, but it is premature to rush the process at this point. There are several high visibility standard development efforts that are competing for our resources - CIP Version 5 comes immediately to mind - and the effect of the recently approved generator validation standards has yet to be determined. As such, we believe the strategy taken in the initial draft of EOP-011-1 is sufficient as it stands; and that that the issue of generator winter preparedness is being actively and effectively pursued elsewhere.
Manitoba Hydro	Yes	(1) The term "BAL-002- WECC -2-Contingency Reserve" is included in the definition section, yet is not a defined term that is used in the standard. This should be deleted. Alternatively, if the terminology is not deleted, there is a drafting inconsistency in R1.2 and R1.3. In these sections the term "load" is not capitalized as it is elsewhere in the standard, thereby implying a different meaning than the term "Load" as defined in the NERC Glossary. If the same meaning was intended, this term should be capitalized. Also, in R1.3, the reference to the U.S. Code of Federal Regulations is inappropriate for non- FERC jurisdictional NERC registered entities. Since Canadian entities are not bound by U.S. law, the reference should be deleted or confined to U.S. registered entities. (2) The definition of "Emergency Energy "refers to a condition where "all other options" have been exhausted. However, since the definition does not refer to any options, it is not clear what the phrase "other options" refers to. This should be clarified. For instance, is the intention to refer to all options other than manual Load shedding?

Organization	Yes or No	Question 17 Comment
Tacoma Power	Yes	Tacoma Power agrees with the overall idea of combining three Energy and Capacity Emergency related plans into one standard, though we are concerned about expanding the new standard to include the Transmission System Emergencies. Our concern is that this standard might be mis-interpreted and/or mis-applied in an attempt to address any and all Transmission emergencies (emphasis on the lower case "e" in emergencies). We feel the standard development team has done a pretty good job so far in addressing this and hope they keep this concern in mind as they continue to develop this standard.
CenterPoint Energy	Yes	CenterPoint Energy appreciates the work of the SDT and the opportunity to provide comments. CenterPoint Energy cannot support the proposed Standard as it is currently drafted for the reasons stated above. The Company understands this is a first draft and provides these comments in anticipation of being able to support a future version of the Standard.
Pepco Holding Inc.	Yes	
Northeast Utilities	Yes	Global Comment: “Emergency Operating Plan” is capitalized but it is not a defined term in the glossary of terms and there is no definition included in this draft of the standard. A definition should be added or it should not be capitalized. Comment on R1 and R5: the standards talk about “operating Emergencies.” There are definitions for “Energy Emergency,” “Capacity Emergency,” and “Emergency” (or “BES Emergency”). If the definition of “Emergency” captures what is needed, then the word “operating” should be deleted. The phrase “operating Emergency” also appears in R5.Comment on R2, R6, and R8: Energy Emergency has a definition in the draft - but “capacity” is not capitalized in “capacity Emergency.” The definition of “Capacity Emergency” in the Glossary is “[a] capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.” So, if this is what the standard

Organization	Yes or No	Question 17 Comment
		means by “capacity Emergency,” then it should be capitalized. R2 should read: “to mitigate Capacity Emergencies and Energy Emergencies.” Same issue in R6 and R8.
Lincoln Electric System	Yes	While appreciative of the drafting team’s efforts in consolidating the Emergency Operations standards, LES believes the following areas may benefit from additional clarification.R9 - Although the Load Serving Entity (LSE) is no longer referenced as an applicable entity within EOP-011-1, the references to the LSE in R9 and Attachment 1 seem to imply that there is still the expectation that the LSE retains compliance responsibilities in case of a potential or actual Energy Emergency. As an example, in Attachment 1 Section B the “Energy Deficient Entity”, which is defined as an LSE or BA in the Attachment 1 Introduction, is required to “communicate its needs to other Balancing Authorities and market participants” (Part 3.1), in addition to updating the RC of the situation “at a minimum of every hour” (Part 3.2). To ensure entities are aware of their respective obligations, recommend either including the LSE as an applicable functional entity within EOP-011-1 or else modifying R9 and Attachment 1 to remove specific references to the LSE.R1, R2 - Per R1 and R2, the Transmission Operator and Balancing Authority are required to develop, maintain and implement an Emergency Operating Plan approved by the Reliability Coordinator. Is the drafting team’s expectation that the process entities establish in R1.3 and R2.3 will take the place of a minimum review requirement? As an example, rather than require entities to review their Plan annually as part of EOP-011-1, all reviews would be accounted for as part of the entity’s revision process developed in R1.3 and R2.3.
City of Austin dba Austin Energy	Yes	City of Austin dba Austin Energy (AE) seeks clarity stating the Emergency Operating Plan required under requirement 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.

END OF REPORT