

Individual or group. (40 Responses)

Name (24 Responses)

Organization (24 Responses)

Group Name (16 Responses)

Lead Contact (16 Responses)

IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)

Comments (40 Responses)

Question 1 (38 Responses)

Question 1 Comments (39 Responses)

Question 2 (37 Responses)

Question 2 Comments (39 Responses)

Question 3 (35 Responses)

Question 3 Comments (39 Responses)

Question 4 (36 Responses)

Question 4 Comments (39 Responses)

Question 5 (26 Responses)

Question 5 Comments (39 Responses)

Question 6 (28 Responses)

Question 6 Comments (39 Responses)

Question 7 (27 Responses)

Question 7 Comments (39 Responses)

Question 8 (34 Responses)

Question 8 Comments (39 Responses)

Question 9 (34 Responses)

Question 9 Comments (39 Responses)

Question 10 (36 Responses)

Question 10 Comments (39 Responses)

Question 11 (28 Responses)

Question 11 Comments (39 Responses)

Question 12 (32 Responses)

Question 12 Comments (39 Responses)

Question 13 (31 Responses)

Question 13 Comments (39 Responses)

Question 14 (33 Responses)

Question 14 Comments (39 Responses)

Question 15 (30 Responses)

Question 15 Comments (39 Responses)

Question 16 (31 Responses)

Question 16 Comments (39 Responses)

Question 17 (34 Responses)

Question 17 Comments (39 Responses)

Individual
Thomas Foltz
American Electric Power
Yes
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).
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.
Yes
Yes
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.
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.

Yes
Individual
Ronnie C. Hoeinghaus
City of Garland
Yes
Yes
Yes
Yes
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.

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.
Yes
Agree with this but do not agree with revising Alert levels - see comments on question 15
Individual
Ayesha Sabouba
Hydro One
Yes
Yes
Yes
Yes
No
The Balancing Authority should gain documented approval from the Load Serving Entity as part of their coordination.
Yes
Yes

Yes
Yes
Yes
No
There should be a maximum time by which the RC must notify impacted parties; it cannot be left stating "as soon as practicable".
Yes
Yes
Yes
Yes
Yes
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.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Group
MRO NERC Standards Review Forum
Joseph DePoorter
Yes
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 be made. The entity can make any change at any time regardless of this bright line criteria.

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

Yes

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 be made. The entity can make any change at any time regardless of this bright line criteria.

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.

Yes

Yes

Yes

Yes

Yes

Yes
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.
No
Since LSE is included in R9, it will need to be added throughout the Standard, where applicable.
Yes
Yes
Yes
We appreciate the efforts of the SDT and the FYRT to consolidate the 3 existing standards from the EOP group into a single standard that is clearer and the requirements are organized by Functional Entity.
Individual
Dave Willis
Idaho Power Company
Yes
Consolidation of the three standards is good, the less redundant standards the better.
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.
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."
Yes

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.
No
This coordination may infact 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."
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.
Yes
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.
Yes
Yes
Yes
Yes
No
No need to create an Alert 4 category. The existing alerts 0-3 seem to be adequate.
Yes
No need to create an Alert 4 category. The existing alerts 0-3 seem to be adequate.
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 capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include

Individual

Amy Casuscelli

Xcel Energy

Yes

Xcel Energy supports moving to a single standard as it will leave less room for potential conflicts between multiple documents.

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.

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.

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.

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 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.

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.

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.

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.

Yes

Yes

Yes

No

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?
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. Requirement 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.
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.
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 next week? The attachment must provide clarity if it is to be included with the standard.
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.
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.
Individual
Michael Falvo
Independent Electricity System Operator
Yes

Yes
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.
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.
Yes
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.
Yes
Same comment for Part 1.2.5 under Q4, above.
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 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.
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.

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.
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.
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.
Yes
Yes
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.
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.
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.

Individual
John Seelke
Public Service Enterprise Group
Yes
Yes
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)]”
Yes
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];”
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)]”
Yes
Yes
Yes
Yes
Yes

Yes
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]....
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.
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 2 2. 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: • 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. • (Deleted the first bullet under Alert 3.) • Energy Deficient Entity has implemented its approved Emergency Operations Plan. During Alert 3, Reliability Coordinators, Balancing 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.

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.

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 CEII, (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.”

Group

Dominion

Connie Lowe

Yes

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.

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.

Yes

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 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.

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 use of UFLS and UVLS automatic Load shedding.’ In which operator controlled manual load shedding was used in EOP-003-2.

Yes

Yes

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.

Yes

Yes

Yes

No

Dominion believes R8 should be included as a sub-requirement in R2, we do not believe it qualifies as a standalone requirement.

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.

Yes
Yes
Yes
Yes
Yes
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 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
Yes
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?

Individual

Keith Morisette

Tacoma Power

Yes

Yes

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.

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.

Yes

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.

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.

Yes

Yes

No

Tacoma Power would suggest the following modification: ...operating Emergency to communicate “as soon as practical” its Emergency...

No

Tacoma Power would suggest the following modification: ...Energy Emergency to communicate “as soon as practical” its Emergency...

Yes

Yes

Yes

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.

Yes

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.

Individual

Lorraine Landers

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

Yes

Yes

Yes

N/A to SC&M Department
N/A to SC&M Department
N/A to SC&M Department
Yes
Yes
Yes
N/A to SC&M Department
Yes
Yes
Yes
N/A to SC&M Department
Yes
No
Group
SPP Standards Review Group
Robert Rhodes
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.
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'.

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 manual Load shedding plan is immaterial in the standard. It definitely needs to be in your Emergency Operating Plan, just not in the standard.

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.

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 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’.

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.

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.

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'.

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 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.

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]"

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]"

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.

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. 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.

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.

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 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.

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.

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.

Group

Florida Municipal Power Agency

Frank Gaffney

Yes

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?
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.
Yes
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.
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.
Yes
Yes
Yes
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".
Yes
See comments to question 10.
Yes

Yes
Yes
Yes
No
FMPA would prefer to retain it as an attachment to the standard.
Yes
FMPA appreciates the work of the SDT to vastly improve the standards.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
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.
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.
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.

Yes

Same comment as for Part 1.2.5 in the response to Question 4.

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.

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.

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 have to "communicate the Emergency and its current and projected System conditions to its Reliability Coordinator"?

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.

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 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 be considered that an individual entity's top priority should be to resolve the Emergency.

Yes

Yes

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.

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")?

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 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.

Individual

Andrew Z. Pusztai

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.

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 specifies an “annual” time requirement to the Emergency Operating Plan review and revision process.

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 on automatic

load shedding;" This revision provides clarification regarding the relationship between manual and automatic load shedding.

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.

Yes

Yes

Yes

Yes

No

Individual

Anthony Jablonski

ReliabilityFirst

Yes

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 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.”

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 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.

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 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.”

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 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].

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

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.]”

No

ReliabilityFirst offers the following comments for consideration: 1. Requirement R9 - ReliabilityFirst believes there should a timeframe associated with how long a Reliability Coordinator has to initiate a NERC Energy Emergency Alert following a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency. ReliabilityFirst recommends the following for consideration: “Each Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1[, within 30 minutes of request.]”

Individual

John Brockhan

CenterPoint Energy

Yes

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. 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."

Yes

Yes

CenterPoint Energy agrees with the proposed coordination role for the Reliability Coordinator.

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.

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.

Yes

Yes

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 defined in the Standard where the term is utilized. CenterPoint Energy recommends keeping Attachment 1 in the proposed EOP-011-1.

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.

Individual

Matt Beilfuss

Wisconsin Electric

Yes
Yes
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.
Yes
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.
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.
Yes
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.
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
No
Group
Duke Energy
Michael Lowman
Yes
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, 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.”

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 “minimize” as used in the requirement is difficult to quantify, and is not a term equated with Auditability.

Yes

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:”

No

See Duke Energy comments on question 3.

Yes

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.

Yes

Yes

Yes

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.

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 steps in an entity’s Emergency Operating Plan has to be performed before declaring and EEA.

Yes

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.

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.

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 obligated is a more appropriate term because LSEs or BAs are not required to serve load, rather they are obligated to do so.

Group

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

Wayne Johnson

Yes

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.

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.

Yes

Other standards adequately cover the time frame requirements.

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 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: • R2.2.2 and R2.2.3: What is the difference between Voluntary Load reductions and Public appeals? • R2.2.4: What governmental programs is the SDT referring to? • 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.

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 the technical background and rationale document to clearly explain the intent of the requirement.

Yes

Other standards adequately cover the time frame requirements.

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: • 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 development meetings, etc. That would be required to merely review and approve/disapprove a Plan. • 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.

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.

Yes

Yes

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.

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.

Yes

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 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.

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?

No

Individual

David Thorne

Pepco Holding Inc.

Yes

No

Why not include many of the other elements included in R2 for Transmission Emergencies?

Yes

Yes

Don't need to duplicate the same requirement in different Standards.

Yes

Yes
Yes
Don't need to duplicate the same requirement in different Standards.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
SERC OC Review Group
Stuart Goza
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.
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:

No

The OC Review Group recommends that adding “Operator controlled” further clarifies R1, Part 1.2.5 R1, 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;

Yes

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:

No

The OC Review Group recommends that adding “Operator controlled” further clarifies R2, Part 2.2.8 Current 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;

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.

Yes

Yes
Yes
Yes
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.
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 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 Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8.

Yes

No

The SERC OC Review Team requests clarification on 1. Alert 1 — Forecast the need for an Energy Emergency. Circumstances: • 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”.

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.

Group

ACES Standards Collaborators

Ben Engelby

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.

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 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.

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.

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.

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 standard is proposing a highly complicated approval process that is unnecessary for reliability.

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.

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 strategy for extreme weather or not. This language only adds confusion and needs to be removed.

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.

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.

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.

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.

No

<p>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.</p>
<p>No</p>
<p>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.</p>
<p>Yes</p>
<p>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.</p>
<p>Yes</p>
<p>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?</p>
<p>Yes</p>
<p>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.</p>
<p>Yes</p>
<p>(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.</p>
<p>Group</p>
<p>DTE Electric</p>
<p>Kathleen Black</p>
<p></p>

Yes
Yes
Yes
Yes
No
<ul style="list-style-type: none"> • 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.”
Yes
Yes
Yes
Yes
Yes
No
<ul style="list-style-type: none"> • 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.
Yes
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.”

Yes

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: o Public appeals to reduce demand. o Voltage reduction. o Interruption of non-firm end use loads in accordance with applicable contracts o Demand-side management. o Utility load conservation measures.

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.

No

Group

Tennessee Valley Authority

Dennis Chastain

Agree

SERC OC Review Group

Individual

Scott Langston

City of Tallahassee

Yes
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.
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.
Yes
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.
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.
Yes
Yes
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.
Yes

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.
Yes
Yes
Yes
No
Individual
Bill Fowler
City of Tallahassee, TAL
Yes
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.
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Yes
No
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No

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Yes

Yes

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.

Yes

Yes

Yes

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.

Yes

Yes

Yes

No

Individual

Karen Webb

City of Tallahassee

Yes

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.
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.
Yes
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.
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.
Yes
Yes
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.
Yes
Yes
Yes

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.
Yes
Yes
Yes
No
Individual
William Temple
Northeast Utilities
Yes
Yes
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.
Yes
Yes
Yes

Yes
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 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.
Group
ISO/RTO Standards Review Committee
Greg Campoli
Yes
Yes
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;
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.

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 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 unit 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 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 become liable for events that it did not cause or over which it had any control.

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.

Yes

Same comment for Part 1.2.5 under Q4, above.

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.

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.

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.

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.

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 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.

Yes

Yes

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 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.

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 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”).

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 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 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.

Individual

Kayleigh Wilkerson

Lincoln Electric System

Yes

Yes

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.

Yes

Yes

No

Refer to comment in Question #3.

Yes

Yes

Yes

Yes

Yes
Yes
Yes
Yes
No
Recommend the Energy Emergency Alert levels remain within the document where they are used.
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.
Group
Florida Power & Light
Mike O’Neil
Yes
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.

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.
Yes
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.
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?
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Current attachment 1 is adequate and adding an additional alert does not add value as forecasted conditions are covered under the existing attachment.
No
Current Attachment 1 provides the details needed to meet the requirements.
No
Individual

Joshua Smith
Oncor Electric Delivery Company LLC
Yes
Yes
Yes
Yes
Yes
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 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).
No
Oncor prefers and supports the use of the revised Attachment 1 in proposed EOP-011-1, with the changes suggested in Question 15.

Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No
<p>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 Risk Factor = 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 these entities should have appropriate situational awareness during emergency operations. For example, after the RC</p>

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.

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 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.

Group

PacifiCorp

Sandra Shaffer
Yes
Yes
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.
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.
Yes
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.
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.
Yes

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 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.
Yes
Yes
Yes
Yes
Yes
Yes
No
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes
Yes
Yes

BPA believes clarification is needed so that a BA may reduce load either directly or through TOP as designed with regard to 2.28 and 2.27
No
BPA believes this applies only if a BA has direct-control load shedding.
Yes
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.
Yes
Yes
Yes
Yes
Yes
Yes
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 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.
Yes
No
Individual
Lisa Martin
City of Austin dba Austin Energy

Yes
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.
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?
Yes
Yes
No
City of Austin dba Austin Energy (AE) believes the RC can coordinate plans without having to approve them.
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.
Yes
Yes
Yes
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.

Yes

City of Austin dba Austin Energy (AE) could work with either format as long as any changes are identified and justified.

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.