Individual or group. (40 Responses)
Name (26 Responses)
Organization (26 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
Question 1 (35 Responses)
Question 1 Comments (35 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
Regarding Requirement R13, there is concern that an operator will be obligated to perform the assessment. Given that the Rationale for Requirement R13, although not auditable, supports the Requirement's wording, suggest revising the Rationale Box to read: The new requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan may describe how to perform the Real-time Assessment. It would also be helpful to confirm that at times no actions may be required if system conditions have not changed within the thirty minute window and that previous contingency analysis or assessments may be used to perform the Real time Assessment for subsequent hours. A suggested revision to Requirement R13: R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes, or in the timeframe specified in an Operating Plan when the Transmission Operator operates in a known state and is unable to perform the Real-Time Assessment every 30 minutes. And for Measure M13: M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes, or in the timeframe specified in an Operating Plan when the Transmission Operator operates in a known state and is unable to perform the Real-time Assessment every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence. Appropriate wording consistent with this should be added to Section F. Associated Documents.
Individual
Daniel Duff
Liberty Electric Power LLC
No
The Operating Instruction should be identified as such by the issuing entity. Not identifying an Operating Instruction will lead to confusion over whether the instruction is a Marketing Instruction or an Operating Instruction. For example, a unit being released from the grid can self-dispatch if the release is for economics. But if the release is considered an Operating Instruction due to conditions of which the GOP is not aware, a violation could occur. Suggest adding one word - Identified - to R3 prior to the term Operating Instruction.
Group
Oklahoma Gas & Electric
Terri Pyle
No
TOP-001-3 R1 & R2 – We take exception to the step back which the SDT has taken with the change of 'address' to 'maintain' in Requirements R1 and R2. The SDT mentioned that one of the reasons for this change was to eliminate the threat of double jeopardy. We don't see that happening with the terminology being proposed. We propose to either continue to use the word "address" or replace it with "support". Rationale Box for R3 – In the Rationale Box for Requirement R3, insert a 'to' between 'due' and 'its' in the last line. R5 – Change 'Balancing Authority' to 'Balancing Authority(s)' in the second line of Requirement R5 to make the requirement consistent with the measure. R6 – Change 'that' in the 3rd line to 'its' for consistency with Requirement R4. Rationale Box for R7 – In

the Rationale Box for Requirement R7, delete the apostrophe in front of ‘This' at the start of the 2nd sentence and also change ‘changes' to ‘change' in the same sentence. R9 – If the SDT's intent was for the 30-minute threshold to apply to both planned and unplanned outages, then the commas surrounding the phrase ‘and unplanned outages of 30 minutes or more' need to be deleted. As written, the 30-minute threshold only applies to unplanned outages. If this wasn't the SDT's intent, it should be. Additionally, the current wording obligates the Balancing Authority and Transmission Operator to notify its Reliability Coordinator whenever an RTU goes down. We should focus on outages of equipment which have an impact on the reliability of the Interconnection. Therefore, we recommend the following language: ‘Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned and unplanned outages of 30 minutes or more for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities, which adversely impact the reliability of the Interconnection.' R10 – We have concerns about the elimination of the caveat regarding identification of facilities by the Transmission Operator for inclusion in the determination of SOL exceedances. Leaning on the ‘as necessary' in Requirement R10 is too much of a stretch. We suggest the SDT re-insert the ‘identified by the Transmission Operator' in R10 as follows: ‘Each Transmission Operator shall perform the following as necessary, when identified by the Transmission Operator, for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:' Change ‘voltages' in Requirement 10, Part 10.2 to ‘voltage'. Make the same change in the Measure as follows: "Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltage, and flow data for Facilities and the status of Special Protection Systems as necessary to determine any identified System Operating Limit (SOL) exceedances within its Transmission Operator Area. R11 – Change ‘Load-interchange balance' to ‘generation-Load-interchange balance' which is consistent with the definition of Balancing Authority as contained in the Functional Model. That definition also includes a component for contributing to Interconnection frequency which the SDT has already incorporated in Requirement R11. VSLs for R8 – If the SDT has not changed its position on the inclusion of ‘other' in this requirement, usage by the way which is consistent with that in Requirement R7, then ‘other' needs to be deleted from the Lower, Moderate and High VSLs for Requirement R8. VSLs for R16 and R17 – Measures 16 and 17 have been inserted in the Severe VSLs for Requirements 16 and 17, respectively. They should be deleted. We recommend that all changes we have proposed for the standards be reflected in the VSLs and RSAW as well.
Individual
Thomas Foltz
American Electric Power
No
R9: AEP disagrees with requiring notification of every planned and unplanned outage of 30 minutes or more, especially since the requirement could be interpreted as applying to the individual RTU's themselves, and irrespective of their impact to the reliability of the BES. AEP believes the proposed language is overly prescriptive, does not accomplish the desired results of the SDT, and provides no benefit to the reliability of the BES. BAs and TOPs should be interested in knowing that they have quality data coming in, i.e., knowing whether or not the data is valid. There is no reliability benefit in requiring notification of every outage of every piece of equipment producing that data. PJM, for example, is in no position to know or determine how or if an individual RTU impacts reliability, or even the quality of the solution of a State Estimator. AEP believes it is far more important to know the *quality* of data feeding the applicable systems (for example, a state estimator), rather than the status of each piece of equipment in the systems which provide that data. AEP requests the drafting team articulate what reliability benefit they believe is gained by providing the status of individual pieces of equipment within R9. The phrase "all planned outages, and unplanned outages of 30 minutes or more" could have multiple interpretations. One possible interpretation is that the 30 minute threshold only applies to an unplanned outage, thereby inferring that notification be made for each and every planned outage, regardless of its duration. Another possible interpretation is that the 30 minute threshold is used for both planned *and* unplanned outages. Please clarify this phrase to make it clear which outages the 30 minute threshold applies to. The text "between the affected entities" seems to imply inter-connections, even though it does not read as such earlier in

R9 (known impacted interconnected entities). AEP recommends changing the language “all planned outages, and unplanned sustained outages” to simply say “all significant outages” and allow the TO and TOP to determine what is significant to the reliable operation of the BES. AEP voted affirmative on draft 3, a draft we consider superior in content to the draft currently proposed. AEP has chosen to vote negative on draft 4, driven by our objections to the latest revisions to R9, as expressed above.
Individual
Chris Scanlon
Exelon
Individual
Denise M. Lietz
Puget Sound Energy
No
The use of the word "maintain" instead of "address" raises the same issues as the word "ensure" in the previous drafts of this standard - if a reliability issue arises, an enforcement entity might find a violation of requirements R1 and R2 simply because an entity failed to "maintain the reliability" of its area (whether or not the entity’s operators took appropriate action to respond to the issue). In addition, the current draft does not address the burden associated with the need to demonstrate compliance with each Operating Instruction under requirement R3. I have previously commented on this issue and I continue to believe that the approach taken to Operating Instructions under the COM-002 standard more appropriately balances compliance burden with reliability needs.
Individual
Joshua Smith
Oncor Electric Delivery LLC
No
Proposed Standard TOP-001-3 R9 States: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. In response to R9, Oncor recommends for the requirement to make it mandatory for BAs and TOPs to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it necessary to notify registered entities that do not have reliability control functions to the BES. Oncor’s suggested rewording for R9: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected TOs, TOPs and GOPs of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Proposed Standard TOP-001-3 R10 States: R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations] 10.1. Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2. Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001- 3 does it require TOs to supply neighboring TOs with this data. Oncor requests R10.2 be removed from the standard due to lack of regional flexibility. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to "a continuous duration exceeding its associated IROL Tv". This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncor’s recommendation is to keep the existing 30 minute time limit.

Group
Dominion
Connie Lowe
Yes
4. Applicability: Suggest that “4.5”be struck as Load Serving Entity was deleted from the applicability list of entities. Dominion suggests that the Rationale for Requirement R13: be modified to state, “…and the timeframe is copied from the approved IRO-008-1, Requirement R2 for consistency.”, as the language is not verbatim from approved IRO-008-1 Requirement 2. M5 - Suggest the “(s)” behind Balancing Authority be removed to match R5.
Individual
Scott Bos
Corn Belt Power Cooperative
Individual
David Jendras
Ameren
No
In our opinion, changes in this version were not significant and the drafting team has not addressed our concerns. (1) We have concerns on what constitutes "Operating Instructions", and over how an entity is to prove compliance once this standard becomes effective. We believe that "Reliability Directives", would be used infrequently under emergency type situations, compared to "Operating Instructions", everyday, common tasks, such as switching, would open up TOP's to an very burdensome way of documenting compliance. (2) We are concerned that the operator will have to focus less attention on the actual operation of the system, and more attention to collecting evidence for future audits. (3) We also have concerns about removing the terminology of EOP-001-1a; R1(and other requirements with similar language) that: “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” We believe that how entities choose to exercise that authority should be determined by each entity, based on their situation. (4) Over the years, the industry has clearly learned what a “Reliability Directive” means and we should not undo this concept, and avoid the confusion that it could create. In addition, the RSAWs introduce the concept of using BES events as a screening tool. We were not able to locate any such information in the Reliability Standard itself, nor does the standard give guidance on when there are no BES events for the period being audited.
Individual
Catherine Wesley
PJM Interconnection
Yes
PJM supports the standard and appreciates the changes made by the SDT.
Individual
Scott Berry
Indiana Municipal Power Agency
No
IMPA does not agree with the use of Operating Instruction within this standard and does not agree with the SDT comments on how the RSAW will be used to “constrain” the potential amount of data an entity will need to provide to an auditor. NERC standards should be able to stand alone and not depend on RSAWs for guidance, especially since entities are audited to the requirements within a standard and not the RSAW. The RSAW states that auditors are encouraged to monitor compliance during the most “critical” events on the entity’s system. Once an auditor states that all Operating Instructions are critical to the BES, then data for all Operating Instructions will need to be supplied to the auditor or a listing of the Operating Instructions for the compliance period with a follow up of evidence (the entity still needs to keep all the evidence for every Operating Instruction for the compliance period just in case that is the one selected). By changing the “reliability directive” wording to “Operating Instruction” within requirements R3 and R5 of TOP-001-3, the SDT has

increased the administrative burden on entities who receive Operating Instructions from their TOP and BA. Once again increasing the administrative burden on entities is the opposite theme of the RAI program which has a goal of helping the industry to concentrate on the “risk” to the BES.
Individual
John Brockhan
CenterPoint Energy Houston Electric LLC
No
R10.2 – CenterPoint Energy agrees with the deletion of the phrase “non-BES” and appreciates the SDT’s consideration of industry comments. However, as stated in the previous round of comments, CenterPoint Energy strongly disagrees with the addition of 10.2 into the TOP Standards, specifically “neighboring Transmission Operator Areas”. CenterPoint Energy agrees with the Functional Model that it is the RC’s responsibility to monitor the wide area. In addition, CenterPoint Energy believes the SDT has overreached in its interpretation of paragraph 60 of the NOPR. CenterPoint Energy’s reading of paragraph 60 finds vague references to monitoring and analysis capabilities but no specific directives to expand the TOP’s view into another TOP Area. Also, CenterPoint Energy is concerned this will create confusion among registered entities as to who exactly has the responsibility to monitor and take action. Furthermore, CenterPoint Energy is not in favor of the most recent version of 10.2 where language referencing, “…identified as necessary by the Transmission Operator…” has been removed. As long as R10.2 remains CenterPoint Energy cannot support the proposed Standard and therefore strongly recommends the SDT delete R10.2. R13. – CenterPoint Energy agrees that an RTA should be run every 30 minutes, however during such events that could occur outside of the System Operator’s control (Ex. Loss of ICCP data); there should be a caveat as to when exceeding the 30 minutes becomes a violation. CenterPoint Energy suggests the following language: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. In instances where a Real-Time Assessment cannot be performed (i.e. loss of ICCP data) the TOP shall take immediate action to restore Real-Time Assessment functionality.
Individual
Brett Holland
Kansas City Power and Light
Individual
Gerald Farringer
Consumers Energy Company
No
Comments: M3 and M5 are over reaching in requiring: In such cases, the Balancing Authority, Generator Operator, and Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator’s Operating Instruction. In the case of generating equipment this can and often is conditional with operating constraints under certain conditions. There may not be specific rules written out to cover all conditions. This is often within the authority of the plant operator concerning what can be done safely with the equipment. This was not an evidence requirement in the current standards and does not need to be one now. We would be in favor of striking the above in both M3 and M5.
Individual
Russ Schneider
Flathead Electric Cooperative
No
The change related to sustained outage being one more than 30 minutes seems tight. 30 minutes isn't very long for an outage.
Group
Seattle City Light
Paul Haase
No

Seattle City Light (SCL) appreciates the efforts made by the Standard Drafting Team to respond to comments from industry and create a quality Standard that is clear and complete. Considerable progress has been made from earlier postings. Some areas remain for improvement. Specifically, SCL diagrees with the R13 requirement for ensuring a real time assessment each 30 minutes, and believes a two-hour requirement to be sufficient and consistent with EOP-008. If 2 hours is too long, SCL urges consideration of a 60 minute requirement, as recommended in an earlier posting. A 30 minutes requirement in our opinion does not add enough reliability benefit to be worth the additional cost, effort, and compliance risk. SCL also continues to recommend that R19 and R20 be deleted from TOP-001-3, as discussed previously. Finally, SCL is concerned with the growing number of BA-specific requirements (R11, R17, and R20) included a TOP-area Standard. While we understand the difficulty of aligning all requirements within the appropriate Standard area (BAL, TOP, etc), we urge extra effort be made to maintain and promote such alignment more than has been done to date. For example, INT-009-2 included BA requirements that do not properly belong in that Standard but were included out of expedience and a lack of willingness to develop an appropriate new SAR. SCL recommends reconsidering the need to include BA-only requirements within a TOP-family Standard, and alternative approaches to addressing these reliability needs in a different Standard.
Individual
John Brockhan
CenterPoint Energy Houston Electric LLC
No
R10.2 – CenterPoint Energy agrees with the deletion of the phrase “non-BES” and appreciates the SDT’s consideration of industry comments. However, as stated in the previous round of comments, CenterPoint Energy strongly disagrees with the addition of 10.2 into the TOP Standards, specifically “neighboring Transmission Operator Areas”. CenterPoint Energy agrees with the Functional Model that it is the RC’s responsibility to monitor the wide area. In addition, CenterPoint Energy believes the SDT has overreached in its interpretation of paragraph 60 of the NOPR. CenterPoint Energy’s reading of paragraph 60 finds vague references to monitoring and analysis capabilities but no specific directives to expand the TOP’s view into another TOP Area. Also, CenterPoint Energy is concerned this will create confusion among registered entities as to who exactly has the responsibility to monitor and take action. Furthermore, CenterPoint Energy is not in favor of the most recent version of 10.2 where language referencing, “…identified as necessary by the Transmission Operator…” has been removed. As long as R10.2 remains CenterPoint Energy cannot support the proposed Standard and therefore strongly recommends the SDT delete R10.2. R13. – CenterPoint Energy agrees that an RTA should be run every 30 minutes, however during such events that could occur outside of the System Operator’s control (Ex. Loss of ICCP data); there should be a caveat as to when exceeding the 30 minutes becomes a violation. CenterPoint Energy suggests the following language: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. In instances where a Real-Time Assessment cannot be performed (i.e. loss of ICCP data) the TOP shall take immediate action to restore Real-Time Assessment functionality.
Individual
Donald E Nelson
Massachusetts Department of Public Utilities
Individual
Erika Doot
US Bureau of Reclamation
No
Reclamation continues to disagree with the use of the term Operating Instruction in TOP-001-3. The drafting team's response to concerns about use of the term "Operating Instruction" rather than reliability directive include "The proposal to use a new defined term ‘Reliability Directive’ is no longer being considered" and "Reliability Directive was never approved by FERC and thus was never part of an officially approved standard. The SDT believes that the use of Operating Instruction in this standard is consistent with the purpose and intent of the COM standards and that the COM standards correctly captured the reliability need as indicated in FERC’s acceptance of the standards. In the FERC NOPR, it was made clear that the concept of a special type of communication for

Emergency situations was not considered acceptable. Operating Instructions issued to generators are not intended to damage critical generating equipment or interfere with competing obligations (e.g., water delivery schedules for hydroelectric producers)." Reclamation respectfully disagrees with the drafting team's interpretation. Reclamation believes that FERC Order directed NERC to define "directive" rather than extend the scope of the standard to all communications between entities regarding bulk electric system operations. The order stated that the proposed standard had defined "transmission operator directives only in emergencies, not normal or pre-emergency times." Reclamation agrees with FERC that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements)." In Reclamation's opinion, the FERC order only directed NERC to better define the term "directive" and allow directives to be issued during normal operations as well as pre-emergency and emergency situations. Reclamation does not believe that FERC required the standard to apply to all non-emergency conversations between GOPs, BAs, and TOPs, with mutually-agreed upon operating plans resulting from these conversations like the COM updates. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Reclamation does not believe that Transmission Operators always understand or consider the equipment capabilities and limitations, or other obligations of generators, and without this understanding Transmission Operators should not have authority for every operating instruction to be mandatory. Reclamation believes that Balancing Authorities and Transmission Providers should be granted wide latitude to issue "directives," which could be defined as "mandatory operating instructions to address transmission system concerns," but directives should be clearly identified by the transmission operator as directives to inform the recipient of the critical nature of the instruction. As written, the standard would instead apply to all operating instructions in all situations, and essentially would allow transmission operators to dictate instructions without understanding competing safety, equipment, regulatory and statutory (including environmental) concerns of generators. This is likely to degrade BES reliability because generator operators will no longer understand the criticality of transmission operator instructions identified as "directives." Reclamation does not believe that the requirements to comply with Reliability Directives in TOP-001 and IRO-001 should be invoked unless the Transmission Operator describes a mandatory instruction as a Reliability Directive. Reclamation appreciates the clarifying language changes in R16, M16, R17, and M17.
Individual
Michelle R. D'Antuono
Ingleside Cogeneration, LP
No
Ingleside Cogeneration L.P. (ICLP) believes that the project team has found an excellent resolution to the issue surrounding “sub-100 kV” and “non-BES” element data. By relying on other standards such as FAC-011-2 – which allows the Reliability Coordinator to dictate that the TOP must consider such facilities while developing their SOLs – the intent is still captured in a binding manner. In addition, NERC’s BES exception process allows the forced registration of critical facilities, which clearly applies to those that would affect a System Operating Limit. The TOP still has the obligation and authority to derive/monitor every SOL, but is not subject to the opinion of a CEA who may think that the criteria used is insufficient. Unfortunately, no such insight has been employed to defuse the standoff related to the execution of “Operating Instructions”. The issue caught FERC’s attention originally as the term “Reliability Directive” was used in the submission of TOP-001-2 – which only applied to situations where an Emergency was declared. The Commission felt that instructions issued by a BA/TOP during near-emergency and normal operating conditions should also be mandatory, which the in-effect version of TOP-001 does not preclude. (It uses the generic un-capitalized term “reliability directive” which can apply to most any communication requiring action by the recipient.) The attempt to clarify the proper situations where a reliability directive can be used, and the evidence required to demonstrate compliance, has led to this impasse. ICLP believes that the way TOP-001-3 is written now, a GOP will be expected to capture the fact that every Operating Instruction was performed, even in low-risk situations where status or routine action is requested. This works against the concept of risk-based compliance and adds an administrative burden that is disproportional to the expected benefits. ICLP believes there is an acceptable alternative. The project team can lessen the severity of the improper execution of an Operating Instruction as compared to a Reliability Directive. This would mean that any instruction not identified by the BA or TOP as a

Reliability Directive would only carry a Low VRF if not executed properly – perhaps a High VRF if an EOP-004-2 defined Event took place as a result. Furthermore, the lack of documentation should not work against the recipient of an Operating Instruction, but would allow for mitigating considerations if a good faith attempt was made in its execution. This would encourage the GOP (in our case) to diligently capture every Operating Instruction, but would not lead to a violation when an understandable oversight took place.
Individual
Leonard Kula
Independent Electricity System Operator
No
1. We continue to have serious concerns over the proposed retirement of TOP-004-2 Requirement R4 without having some of the requirements in TOP-001-3 revised to address the reliability need for confirming and re-establishing valid SOLs/IROLs in an unknown or unstudied state. We believe that there are times when, following some power system event, when there are no derived set of limits – particularly transient stability limits. We believe that the revised TOP standards do not compel an entity to derive limits following such events within an acceptable time frame. That direction was clearly specified in the existing TOP-004-2 R4: R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. We believe that removal of this requirement, without adequately and clearly replacing it, significantly diminishes reliability. We submit the following detailed comments for consideration by the SDT: a. The SDT's response to our previous comment suggests there is always either a set of limits in service or an Operating Plan which provides guidance to adjust the limit until a new set of limits are analyzed and determined. We are unable to find a requirement in the standard that stipulates the Operating Plan shall have guidance to adjust the limit until a new set of limits are analyzed and determined. This requirement doesn't appear to exist. b. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined, what to do upon experiencing an SOL exceedance, and acceptable timeframes to mitigate SOL exceedances. The above response addresses SOL exceedance only; but the issue we raised is on the need to re-establish SOLs themselves, which may not already exist for the conditions encountered. How does an entity know if it has exceeded an SOL if an SOL was not previously developed or is invalidated by the prevailing conditions? c. The SDT believes that the situation described has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to Requirement R13, perform a Real-time Assessment every 30 minutes, and Requirement R14, implement Operating Plans to mitigate an SOL Exceedance, as well as the guidance provided on Operating Plans in Section F. Furthermore the standard does not prohibit an entity from performing an RTA more frequently in response to an unplanned system event. The SDT's response suggests that the concept of confirming and re-establishing SOL's is covered in the entities' Operating Plan. An Operating Plan, consistent with the NERC definition, is general and predictive in nature and by itself does not mandate the confirmation or re-establishment of limits when in an unstudied state. The concept of confirming and re-establishing SOL's for the prevailing condition is only captured in the SOL Exceedance White Paper under the "Stability Limit Exceedance" section as follows: "Pre-determined Transient and voltage Stability limits must be re-established when changes in the system (both expected future changes and actual Real-time changes) occur that render these pre-determined limits invalid." This sentence is presented in a standard requirement language. We do not understand why this is not stipulated in the standard itself such that it becomes an enforceable requirement to address the potential reliability gap created by retiring TOP-004-2 Requirement R4. Having this language in a whitepaper does not make this mandatory. 2. We offer the following comments on three requirements in TOP-001-3: i. R7: We do not agree with the added qualifier "within its Reliability Coordinator Area" since we believe that all TOPs need to assist their neighbor TOPs regardless if they are in the same RC area. We propose to remove this qualifier from R7. ii. R10: We understand the intent of the proposed changes to Parts 10.1 and 10.2, but these changes have made the two parts confusing and inconsistent. From a reliability standpoint, it is intuitive that a TOP needs to monitor all Facilities within its TOP area that may have an impact on SOLs/IROLs. Part 10.1 is unclear on this whereas Part 10.2 is more specific on the parameters of the concerned Facilities. We suggest adding the word "all" before "Facilities" in Part 10.1. iii. R11: This requirement is redundant with BAL-002 since the

latter already requires a BA to assess all contingencies – which should include SPS operations resulting in generation and/or load reduction, to determine its reserve requirements. We suggest removing R11.
Group
ISO RTO Council Standards Review Committee (SRC)
Greg Campoli
No
Requirement R11, as proposed, states, “Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.” The SRC suggests that Requirement R11 is duplicative of requirements and obligations placed on Balancing Authorities in the BAL Standards and, therefore, suggests deletion of Requirement R11.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
ATC recommends that the SDT consider removing the following language from the proposed “Real-time Assessment” definition: “known Protection System and Special Protection System status or degradation,” The revised definition would be as follows: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) -- Reason for removal of the language: This language should be removed because it is unrealistic for entities to perform a new real-time assessment every 30 minutes that incorporates the necessary contingency definition changes driven by a protection system failures. EMS systems using real-time contingency analysis tools do not include contingency definitions for the myriads of potential tripping scenarios for various failed protection systems. Therefore, off-line analysis would need to be performed by the system operator or another employee. Because off-line analysis would need to be used, it is an unreasonable burden to have to perform this assessment every 30 minutes as would be required by the proposed Requirement R13.
Group
Con Edison, Inc.
Kelly Dash
No
Requirement R13 is problematic. The 30 minute requirement in R13 is too restrictive and inconsistent with EOP-008, which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be granted the same time consideration to restore real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13: • Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every two hours. • Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every 30 minutes when the EMS & SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform real-time assessments within two hours.
Group
National Grid
Michael Jones
No
Requirement R13 is problematic. The 30 minute requirement in R13 is too restrictive and inconsistent with EOP-008, which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be

granted the same time consideration to restore real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13: • Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every two hours. • Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every 30 minutes when the EMS & SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform real-time assessments within two hours.
Group
Duke Energy
Michael Lowman
No
R1&R2: Duke Energy still has concerns regarding the wording associated with R1 and R2. The SDT stated in their consideration of Duke Energy comments that, “Specific actions for specific situations will be covered under the applicable standards.” Our fear is that the language can still be viewed as a failure to act or a failure to maintain. Duke Energy understands and agrees, through informal discussions with the SDT, that the intent of R1 and R2 is that the BA and TOP must take some action in order to maintain the reliability of the BES and not whether the BA or TOP succeeded in said action. R9: Duke Energy agrees with the removal of “sustained” and the addition of a timing requirement for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. However, would like the SDT to provide a response to the following question, If the primary channel (RTU, etc.) is out of service and the backup is working properly, then is the expectation for the BA and TOP to notify the RC and other entities affected that the primary communication channel is out service? (Even though monitoring, assessment capabilities, etc. have not been affected). Duke Energy understands and agrees, through informal discussions with the SDT, that if back-up communication channels from the BA and TOP are still providing data then there is no need for communications to the RC and others affected as described in R9. Associated Documents (SOL Exeedance document): Duke Energy requests clarification on the compliance ramifications of the Associated Documents section. Upon our review of Appendix 3A of the NERC Rules of Procedure, Associated Documents are not included in the Appendix, and thus an entity would not consider the section to be an enforceable part of the standard for compliance purposes. We do not feel that including a URL, rather than attaching the entire document to the standard clears up any confusion the industry may have on this issue. Duke Energy maintains that this document could be viewed as an expansion of what is currently considered to be an SOL, and feels that this document should be viewed as purely a Guideline/Technical Basis document as is currently labeled in other NERC standards (see CIP-004-7).
Individual
Daniel Duff
Liberty Electric Power LLC
No
No, the SDT should have further defined "reliability directive" instead of punting and simply replacing it with the term "Operating Instruction".
Individual
Jason Snodgrass
Georgia Transmission Corp
No
(1) GTC requests the drafting team to develop separate requirements for the DP to comply with Operating Instructions received by the TOP and BA which is consistent with NERC’s Functional Model relating to real-time switching activities at non-BES facilities. By making this change, the requirements will be made clearer that the Operating Instructions that the DP receive from the TOP with respect to the defined term Operating Instruction, correspond to switching non-BES facilities that “impact” the output of an Element of the BES (shed or shift load). GTC believes the typical scenario the drafting team is considering is from a TOP control center to a DP dispatch center that does not own BES equipment, but can impact the output of an Element of the BES (by shedding or shifting load). The aforementioned comments relating to DP switching non-BES facilities provides additional support of why the DP should be ungrouped with the BA and GOP which may own and operate BES facilities. This separation of BES vs non-BES associated with implementing Operating

Instructions reduces the current ambiguity for those NERC registered DPs that are also registered as Transmission Owners but are not registered as Transmission Operators with respect to requirements R3 and R5. With the following changes made to the requirements, GTC would be comfortable voting affirmative on this standard: • Each Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator to reduce voltage, shed load, shift load, and/or implement system restoration plans on non-BES facilities unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. • Each Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority to reduce voltage, shed load, or shift load on non-BES facilities unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. (2) If however, the current draft standard passes this ballot GTC would greatly appreciate for the Standard Drafting team to expand the Rationale for Requirement R3 corresponding with the DP by inserting the following language: As identified in the NERC functional Model, Distribution Provider's must perform switching tasks to implement voltage reduction, load shed, or as part of a system restoration plans as directed by the Transmission Operator or Balancing Authority. (3) This Standard does not apply to a Transmission Owner; will the drafting team confirm GTC's assumption that the recipient field personnel of an Operating Instruction who performs the switching inside "transmission stations" are assumed to be handled by the TOP via R1? (4) The recipient entities of Operating Instructions performed in the field that do not own control centers will rely on the operator logs and voice recordings of the issuing entities as compliance evidence. Those entities (issuing vs recipient) which may have different data retention periods for compliance enforcement protection increases compliance risk to recipient entities that have zero control over the data. This risk can be mitigated by incorporating a reasonable data retention period into the requirements that are consistent with compliance enforcement practices. It should be noted, that the 90 day retention period under section C of this standard does not align with any compliance enforcement Regional Entity expectations and only adds confusion.
Group
Colorado Springs Utilities
Kaleb Brimhall
No
Thank you standard drafting teammates for all of your work on this complex standard! R13 Comment: R13 requires that a Real-time Assessment is performed at least once every 30 minutes. We believe that this is in conflict with EOP-008 which allows for a two hour transition period to back-up control center. How does the standard drafting team anticipate that an entity that is failing over to a back-up control center is to maintain compliance with this requirement? This requirement needs to be modified to make sure it is consistent with EOP-008. General Comment: We re-submit our comment concerning the use of the word "maintain" which has much the same implications as "ensure". We concur that entities must act timely and prudently for the reliability of the BES, but entities should not be unduly held accountable for system conditions outside their control that lead to reliability issues of the BES. We favor the word "address" and "address reliability" to "maintain" and "maintain reliability." The fact that a reliability issue or even a black-out has occurred is not sufficient to prove that entities were not appropriately acting. We must avoid requirement language that attaches liability just because a reliability event occurs.
Group
SPP Standards Review Group
Robert Rhodes
No
TOP-001-3 R1 & R2 – We take exception to the step back which the SDT has taken with the change of 'address' to 'maintain' in Requirements R1 and R2. The SDT mentioned that one of the reasons for this change was to eliminate the threat of double jeopardy. We don't see that happening with the terminology being proposed. Rationale Box for R3 – In the Rationale Box for Requirement R3, insert a 'to' between 'due' and 'its' in the last line. R5 – Change 'Balancing Authority' to 'Balancing Authority(s)' in the second line of Requirement R5 to make the requirement consistent with the measure. R6 – Change 'that' in the 3rd line to 'its' for consistency with Requirement R4. Rationale Box for R7 – In the Rationale Box for Requirement R7, delete the apostrophe in front of 'This' at the start of the 2nd sentence and also change 'changes' to 'change' in the same sentence. R9 – If the

SDT's intent was for the 30-minute threshold to apply to both planned and unplanned outages, then the commas surrounding the phrase 'and unplanned outages of 30 minutes or more' need to be deleted. As written, the 30-minute threshold only applies to unplanned outages. If this wasn't the SDT's intent, it should be. Additionally, the current wording obligates the Balancing Authority and Transmission Operator to notify its Reliability Coordinator whenever an RTU goes down. We should focus on outages of equipment which have an impact on the reliability of the Interconnection. Therefore, we recommend the following language: 'Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned and unplanned outages of 30 minutes or more for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities, which adversely impact the reliability of the Interconnection.' R10 – We have concerns about the elimination of the caveat regarding identification of facilities by the Transmission Operator for inclusion in the determination of SOL exceedances. Leaning on the 'as necessary' in Requirement R10 is too much of a stretch. We suggest the SDT re-insert the 'identified by the Transmission Operator' in R10 as follows: 'Each Transmission Operator shall perform the following as necessary, when identified by the Transmission Operator, for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:' Change 'voltages' in Requirement 10, Part 10.2 to 'voltage'. Make the same change in the Measure. R11 – Change 'Load-interchange balance' to 'generation-Load-interchange balance' which is consistent with the definition of Balancing Authority as contained in the Functional Model. That definition also includes a component for contributing to Interconnection frequency which the SDT has already incorporated in Requirement R11. VSLs for R8 – If the SDT has not changed its position on the inclusion of 'other' in this requirement, usage by the way which is consistent with that in Requirement R7, then 'other' needs to be deleted from the Lower, Moderate and High VSLs for Requirement R8. VSLs for R16 and R17 – Measures 16 and 17 have been inserted in the Severe VSLs for Requirements 16 and 17, respectively. They should be deleted. We recommend that all changes we have proposed for the standards be reflected in the VSLs and RSAW as well. Implementation Plan Split the 2nd paragraph on the 4th page into two sentences. Do this by replacing '...SW Outage Report, and this implementation plan...' with '...SW Outage Report. This implementation plan...' at the end of the 3rd and the beginning of the 4th lines of the paragraph. In the paragraph under General Considerations on page 4, delete the 's' on 'Requirements R5' at the end of the 3rd line. In the 1st paragraph under Implementation Plan for Definitions on page 8, replace 'definitions' in the 4th line with 'definition.' SOL Whitepaper The '3.' at the top of page 3 should be '4.'. Split the 1st sentence of the paragraph immediately following '4.' above into two sentences by making the following change in the 3rd line of that paragraph. Replace '...Requirement R2 sub-requirements, the assumption being that...' with '...Requirement R2 sub-requirements. The assumption being that...'. In the last line under the first 3 on page 4, change 'limit' to 'limits'. Replace 'Owner' at the top of page 6 with 'Owner's'. Capitalize 'process' at the end of the last line of the Operating Process definition on page 10. NOPR Issues The language quoted on page 2 for IRO-008-2, Requirement R2 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 2 for IRO-008-2, Requirement R4 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 3 for IRO-002-4, Requirement R2 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 7 for TOP-001-3, Requirement R11 is not consistent with the language currently posted for comment and ballot. The language quoted on page 7 for TOP-001-3, Requirement R13 is not consistent with the language currently posted for comment and ballot. The language shown is actually Requirement R11 of the posted version. The reference to proposed IRO-014-2, Requirement R1 on page 20 should actually be to IRO-014-3. Part 1.1 of IRO-017-1, Requirement R1 shown on page 20 is missing the 1.1 designation. The language quoted on page 21 for TOP-003-3, Requirement R5, Part 5.3 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 21 for IRO-010-2, Requirement R3, Part 3.3 is not consistent with the language posted in the final ballot package of October 10, 2014.
Group
Bonneville Power Administration
Andrea Jessup
No

BPA’s primary concern is with the way Requirement R8 is written. It requires BPA to inform the RC and any impacted TOP’s and BA’s of an actual or expected operating condition that results in or could result in an Emergency. Emergency is defined in the NERC Glossary as: “Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System” BPA could interpret this to mean that our dispatchers should call the RC anytime any 115kV line anywhere on BPA’s system is threatened by fire, wind, ice, or other conditions. BPA is also concerned about having to inform these other parties of “expected operating conditions …that could result in an Emergency.” It is not clear to BPA how an auditor will interpret this. BPA is concerned that, given how broad the definition of “Emergency” is, we might violate R8 for not anticipating a particular operating condition or its full consequences. Again, “Emergency” does not merely refer to a WECC-wide stability event like September 8. This is written such that it includes a simple trip of a 115kV line.
Group
MRO- NERC Standards Review Forum
Joe Depoorter
No
: The NSRF cannot support R1 and R2 as written within the proposed TOP-001-3. The NSRF believes that as written, these Requirements are a catch all, ambiguous, and not measurable. FERC Order 693, section 253 states, “…compliance will in all cases be measured be determining whether the party met or failed to meet the Requirement….” The NSRF does not understand what is being required by the TOP and BA, respectfully. Granted, the SDT wants a TOP and BA to “maintain the reliability of its Area via its own actions or by issuing Operating Instructions”. The NSRF views this as what a TOP and BA should be doing at all times. But in order for a TOP or BA to show proof of compliance, the industry needs to know what is required of them? The SDT has not provided any relief to the TOP and BA as we move into risk based compliance activities. The NSRF has referred to the Standards Process Manual to point out to the SDT that Standards Process Manual section 2.4 describes a “Results Based Requirement” as “Each requirement of a reliability standard shall identify what Functional Entities shall do, and under what conditions, to achieve a specific reliability objective and not how that objective is achieved”. In FERC’s Order regarding NERC’s Five-Year Performance Assessment [149 FERC ¶ 61,141, P 70 (2014)], the Commission recently highlighted the importance of improving consistency: “The Commission recognizes and supports NERC’s efforts to increase consistency and promote coordination across the ERO Enterprise. A key element of consistency is the transparency of the ERO Enterprise’s processes and its outcomes. Improved consistency and coordination helps to clarify the roles and responsibilities of NERC and the Regional Entities and should lead to more efficient and uniform work practices. Specifically, we believe that a focus on achieving consistent compliance and enforcement outcomes (e.g., monetary penalties, registration decisions, and consistent understanding of Reliability Standard requirements) while not equating consistency with a “lowest common denominator” approach would provide the greatest benefit to registered entities.” As written, R1 and R2 do not provide a “consistent understanding of Reliability Standard requirements”. The NSRF has even given proposed rewrite of “A possible rewrite of R1 and R2 to read: ”Each (BA, TOP) shall issue Operating Instructions to address the reliability of its area when direct actions require more assistance “. The SDT replied that “The SDT does not believe that Requirements R1 and R2 are problematic. The requirement simply states that an entity maintain the reliability of its area by the means it has at its disposal - either through its own actions or by issuing Operating Instructions. If the entity does that, then the SDT believes it has met the spirit and intent of the requirement”. The NSRF does not agree with the “spirit” that the SDT believes is the intent of the Requirements. If the SDT believes that the “TOP and BA shall maintain the reliability of its area by the means it has at its disposal”, then that should be clearly stated within R1 and R2. The NSRF believes that section 253 of FERC Order 693 could then be adhered, too. The NSRF recommends that the SDT consider removing the following language from the proposed “Real-time Assessment” definition: “known Protection System and Special Protection System status or degradation,” The revised definition would be as follows: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be

provided through internal systems or through third-party services.) Reason for removal of the language: This language should be removed because it is unrealistic for entities to perform a new real-time assessment every 30 minutes that incorporates the necessary contingency definition changes driven by a Protection System failures. EMS systems using real-time contingency analysis tools do not include contingency definitions for the myriads of potential tripping scenarios for various failed protection systems. Therefore, off-line analysis would need to be performed by the system operator or another employee. Because off-line analysis would need to be used, it is an unreasonable burden to have to perform this assessment every 30 minutes as would be required by the proposed Requirement R13. What happens when the analysis cannot be accomplished within 30 minutes due to other emergency conditions? Whereby the Entity is reacting to a priority situation? With regard to R13, we believe the SDT has improved the language by revisions such that the TOP shall “ensure that a Real-time Assessment is performed at least once every 30 minutes;” however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, we would recommend the following language: R13: “Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP.” Measure M13 would need commensurate edits to conform with this R13 language. Entities have made these comments before and the SDT did not agree as they said; The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn’t about maintaining RTCA or any other specific tool, it’s about maintaining situational awareness at all times. No change made. The first concern is the NSRF believes that without further clarification, System Operators will not have the “situational awareness” because they will not know “known Protection System and Special Protection System status or degradation…” per the Real-time Assessment definition, thus will most likely be non-compliant on a daily basis. A 4000 breaker Transmission system can have up to 20,000 (4000 x 5 parts of a Protection System) parts that would need to be tracked every 30 minutes. This is unrealistic and not physically possible. The SDT continues to use the words “have situational awareness” in their response to comments, and that the Requirement is not about an RTCA. But without using the RTCA, how will the System Operator prevent instability, uncontrolled separation or Cascading outages, per the Purpose of this proposed Standard? The Real-time assessment must consist of existing and potential operating conditions, per the definition. A System Operator cannot calculate all the minimum inputs every 30 minutes without using some type of calculating device. The NSRF would also wish to point out that the SDT may believe that an Entity’s RTCA may run every several minutes and thus fulfilling the 30 minute requirement. An Entity cannot be directed to have an RTCA and most RTCA systems, do not function properly if all the data points are not provided, ie, transmission lines out of service due to severe weather, thus unable to provide the required “situational awareness”.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Group
ACES Standards Collaborators
Ben Engelby
No
(1) Requirements R1 and R2 are vague, overly broad, and duplicative of other requirements and will be difficult to demonstrate compliance with and as a result may distract System Operators from their reliability mission. If there is a disturbance on the transmission system, there could be a potential violation of R1 and R2 because the TOP/BA did not “maintain reliability” of its area regardless whether is actions were appropriate or not. This requirement is very subjective and will allow auditors or investigators to interpret a system operator’s actions after-the-fact to determine if they acted appropriately. There is nothing in these requirements that allow for a reasonable measure of performance. The Compliance Enforcement Authority will evaluate whether actions were taken, Operating Instructions were issued, and whether or not reliability was maintained. There could be a

violation whenever a disturbance occurs in the TOP/BA area including events beyond their control such as tornadoes or hurricanes, as reliability was not maintained. These requirements are duplicative with many other requirements. For example, failing to initiate an Operating Plan to mitigate an SOL exceedance in R14 is failing to take action or issue Operating Instructions to maintain reliability. While the RSAW's do attempt to limit the burden of proving compliance with every Operating Instruction by instructing auditors to monitor compliance during events, RSAWs are simply guidance documents that an auditor is not obligated to follow. Thus, a TOP and BA must be able to prove compliance by retaining every Operating Instruction and that it acted in response to every operating threat. This is a tall order that will distract System Operators from their reliability mission and as a result be a detriment to reliability. While System Operators are already tasked with logging actions and information throughout the day, their standards for documenting information likely are not at a level that would be auditably compliant. Thus, System Operators will have to focus time and energy that should be focused on Operating the system with writing auditably compliant logs. A better solution would be to revert these requirements back to the authority requirements of the existing standards. The data retention section of this standard exacerbates the issue by requiring evidence that is not an operator log or voice recording to be retained for up to two calendar years. What other evidence does the drafting team foresee will be used to demonstrate compliance? These requirements need to be revised to include a reasonable measure of performance and the VSL table should be modified to account for instances where contributing factors led to reliability not being maintained. (2) Requirements R1 and R2 do not line up with the functional model. A TOP is obligated per R1 "to act to maintain the reliability of its Transmission Operator Areas via its own actions or by issuing Operating Instructions." This means that a TOP must respond to all reliability threats including those that are not its responsibility. Consider a large generating plant trips and frequency declines significantly but there are not SOL or IROL violations or voltage violations. In other words, the transmission system is within operating limits with the exception of frequency. The TOP should not act because the BA should be acting to recover frequency. In fact, if the TOP does act, it likely will be detrimental to reliability. However, the TOP would be in technical violation of the requirement because it did not act and or issue Operating Instructions in response to a reliability threat within its Transmission Operator Area. (3) Requirements R3, R4, R5, and R6 should be modified in several ways. First, we disagree with the classifications of High VRF and Severe VSL for failing to comply with an Operating Instruction in all instances. Failing to follow an Operating Instruction during routine operations, is unlikely "to directly cause or contribute to Bulk-Power System instability, separation or a cascading sequence of failures" as required by a High VRF. As an example, the failure to implement the Operating Instruction correctly in the Arizona-Southern California did not directly cause the outage as it was not a root cause. Rather it was the initiating action and other standards violations were required to cause the blackout. The VRF should be reduced to Medium. Second, the VSL table should be graduated to allow for instances of both Operating Instructions issued during Emergencies and Operating Instructions issued during non-Emergencies. Finally, the requirements should be modified to take into account Emergency and non-Emergency conditions. Failing to implement an Operating Instruction during a non-Emergency does not pose the same risk to BES reliability as failing to implement an Operating Instruction during an Emergency. Failing to implement an Operating Instruction during a non-Emergency would require other standards violations to cause a blackout. Under the current draft, all failures to comply with Operating Instructions could result in fine of $1 Million per day, per violation. This does not seem reasonable, especially in the instance of a small generator or Distribution Provider that would have limited impact on reliability from failing to implement varying types of Operating Instructions. (4) Requirement R7 has reverted back to comparable Emergency procedures, which the drafting team has acknowledged in the rationale box of the previous posting as "impossible to measure." Has the drafting team determined a way to measure and if so has it been documented? (5) Requirement R8 should be limited to known impacted Balancing Authorities and known impacted Transmission Operators "within the RC Area." This modification would be consistent with R7. As currently written, R8 requires a TOP to inform all other BAs and TOPs in the Interconnection, as they would be impacted entities. Further, the percentages in the VSL do not accurately reflect the amount of entities that would need to communicate. The metric of 15 percent or less of the impacted TOPs assumes that 10 or more entities should be notified. In an Emergency, the RC and neighboring entities should be notified, as system operators should be focused at mitigating the conditions leading to the Emergency. The RC is responsible for wide-area reliability. (6) Requirement R9's VSL table needs to be modified. As written, a Severe VSL will result if a BA/TOP does not contact four or

more known impacted interconnected entities. The requirement does not state how many entities must be contacted. If the BA/TOP contacts its RC, the burden should shift to the RC to coordinate with other impacted entities. The requirement needs to be clarified and VSL table should be modified. (7) Requirement R10 has improved with the removal of non-BES facilities. (8) Requirement R11 is duplicative with many of the NERC BAL standards. A BA is expected, as required by these BAL standards, to monitor the load-interchange balance and frequency its own area to calculate ACE as part of its efforts to maintain compliance with CPS1, CPS2, DCS, and eventually with the Balancing Authority ACE Limit, defined within NERC Standards BAL-001-2, and currently on file with FERC. Moreover, several other BAL requirements identify criteria that a BA must use to properly calculate its ACE and identify the need for redundant mechanisms to monitor the ACE components. (9) Requirement R15 is duplicative with R8. Both requirements address the TOP notifying the RC of actual operations that could result in an Emergency. Actions taken to return the system to within limits when a SOL has been exceeded could fall into this category. R15 should be struck. (10) The purpose statement is vague and overly broad and should be revised. The purpose of the Energy Policy Act of 2005 is to ensure reliability operation which by definition includes preventing instability, cascading, and uncontrolled separation. Thus, this is the purpose of the reliability standards as a whole. Furthermore, the way the purpose statement is written implies that instability, uncontrolled separation, and cascading may not adversely impact the interconnection with the “that adversely impact the reliability of the Interconnection.” How would instability, uncontrolled separation, and cascading not adversely impact the interconnection? (11) Thank you for the opportunity to comment.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst abstains and offers the following comments for consideration. 1. Requirement R1, R2, R3 and R4 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Failure to do so could result in a situational awareness issue (i.e. lack of accurate data and information) for the System Operator that could jeopardize system reliability. Additionally, and absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst understands that a finite timeframe may not be appropriate to be stated in the standard to cover all circumstances, but offers a suggestion to require the TOP to define its needs when issuing Operating Instructions. ReliabilityFirst suggests the following revised language for consideration. R1 - Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions [along with allocated time constraints for notification if the Operating Instructions cannot be performed]. R2 - Each Balancing Authority shall act to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instruction [along with allocated time constraints for notification if the Operating Instructions cannot be performed]. R4 - Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within the time constraints allocated by the Transmission Operator] of its inability to perform an Operating Instruction issued by its Transmission Operator...” R6 - Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within the time constraints allocated by the Balancing Authority] of its inability to perform an Operating Instruction issued by that Balancing Authority.” 2. Requirement R10, Part 10.1 and 10.2 – ReliabilityFirst believes the lead-in language in R10 (“…shall perform”) does not read well with the two sub parts. ReliabilityFirst recommends the following for consideration in order to make the wording of the parent and sub parts read more clearly: a. 10.1 - Monitoring Facilities and the status of Special Protection Systems, within its Transmission Operator Area, and b. 10.2 - Obtaining and utilizing status, voltages, and flow data for Facilities and the status of Special Protection Systems, outside its Transmission Operator Area. 3. Requirement R12 – ReliabilityFirst requests clarification from the SDT for instances when a TOP identifies an IROL which is outside of the set of predefined identified IROLs, are the TOPs also required to not operate outside these unidentified IROLs per Requirement R12? 4. Requirement R14 – ReliabilityFirst believes the word “initiate” should be replaced with the word “execute”. Because Operating Plans consist of “…a group of activities”, we

would not want to only require the TOP to start (i.e., initiate) the first activity of the Operating Plan, but execute all activities that are part of the Operating Plan to mitigate the issue at hand.
Group
PacifiCorp
Sandra Shaffer
No
PacifiCorp does not favor approval of TOP-001-3 as drafted. PacifiCorp supports the comments of MidAmerica and objects for the following additional reasons: (1) The phrase “identified phase angle and equipment limitations” used in the proposed definition of Real-Time Assessment is vague, specifically the use of the term “identified.” Clarification would be needed since compliance with R13 requires a Real-Time Assessment every 30 minutes. (2) In addition, not all EMS systems can monitor phase angles using current online tools. This technology is not available in our system and we are not sure when it will be.
Individual
Texas Reliability Entity, Inc.
Texas Reliability Entity, Inc.
No
WRT to Requirement 10: Should Remedial Action Scheme be used instead? How will an entity support “as necessary”? How will a CEA accept “as necessary”? Transmission Operator Area ignores a Transmission Operator that DIRECTS ”the operations of the transmission facilities” and may cause a reliability gap in the Standard in this Interconnection. The VSLs are geared towards zero tolerance. Example- R8 appears to be a violation if one TOP is not informed. R10 High VSL is one item is not monitored (Is that one line?) The R8 VSL adding a component to the R8 Requirement that does not otherwise exist in R8. This VSL modification of the R8 Requirement weakens the Requirement’s beneficial effect on the reliability of the BES. In effect, the VSL modification negates the requirement in R8 by adding at the end ‘unless you can’t’. The added phrase in the VSL needs to be added in the R8 Requirement, where it can be properly considered as part of the Requirement, or removed from the VSL. R8 VSL has the phrase “when conditions did permit such communications” added to the description of the violations. This phrase does not exist in the Requirement. If the SDT wishes to change the meaning of the Requirement it should add that quoted phrase to the Requirement itself. R16 VSL has unintentionally included “Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its” in the VSL and the quoted section should be removed. Also change the two occurrences of “Balancing Authority” to “Transmission Operator”. R17 VSL has unintentionally included “Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its” in the VSL and the quoted section should be removed. The removal of the phrase "may be performed either a day ahead or as much as 12 months ahead” in the revised definition of Operational Planning Analysis may impact the Real-time reliability of the Reliability Coordinator Area. The issue is that the new definition only refers to next-day operations. There is a possible gap since a time frame for the evaluation of one day up to 12 months may not be considered by registered entities because of the removal of the subject language. This gap is compounded by the fact that the Time Horizons for most of the requirements are either Same Day or Real-Time.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No
ERCOT respectfully submits the following comments: 1. Regarding Requirement R13, ERCOT requests clarification that Requirement R13 does not apply during time periods where entities lose telemetry or EMS (an abnormal or emergency condition). During such time periods, registered entities may not be able to perform a Real-Time Assessment within 30 minutes (per definition). The reliability standards contemplate and allow for emergency circumstances and emergency plans in

other Reliability Standards. To ensure consistency, the SDT should provide clarification regarding the applicability of this requirement by either: limiting applicability to normal operating conditions; providing a metric for percentage of availability that constitutes compliance, or revising the requirement to account for system issues as mentioned. 2. ERCOT reiterates concerns regarding use of the term “Operating Plan” in Requirement R14. Because the definition of “Operating Plan” states that it is a “document”, use of the term “Operating Plan” may be too restrictive to allow for necessary actions to be taken as contemplated in Requirement R14 as most actions taken occur per procedures or constraint management plans, but the universe of responsive actions cannot be easily documented in a single “document”. To ensure that system operators have the flexibility needed to take whatever actions they deem necessary to mitigate an SOL, ERCOT suggests removal of the term Operating Plan. 3. ERCOT respectfully submits that Requirements R1 and R2 are unnecessary because they are redundant with other requirements for a BA and TOP in Same-Day and Real Time Operations. ERCOT suggests deletion of Requirements R1 and R2.
Individual
Russell A. Noble
Cowlitz PUD
No
Cowlitz submits negative votes due to the SDT responses surrounding Real-Time Assessment (RTA) being performed at least every 30 minutes, and is concerned comment submitted by the stakeholders have not been adequately addressed. Cowlitz disagrees with the SDT responses which imply a full quality RTA can be performed in all circumstances. Comment submitted by Northeast Power Coordinating Council addressed a concern over the inability to perform RTAs during an EOP-008-1 primary to backup control center transition, and that responsible entities should be allowed a 2-hour window in which to reestablish a 30-minute RTA schedule. The SDT response stipulates that EOP-008-1 supports continuance of 30-minute RTAs during the transition. While Cowlitz agrees that the 30-minute RTA must continue, it will be limited to the available data from which to complete the assessment. Although EOP-008-1 allows for a 2-hour transition plan, it does not imply a 2-hour suspension of registered functional obligation is allowed; however, it does not require all systems to be maintained operational during the transition. The objective is to “ensure continued reliable operations of the Bulk Electric System” during an emergency; this of course is contingent upon circumstances not exceeding reasonable expectations of an entity’s ability to respond to emergency situations. The objective is to have a planned response to a contingency – loss of a control center – that will restore critical control and awareness tools necessary for continued functional obligations, not a guaranteed continuance of all the control and awareness tools. Cowlitz respectfully requests the SDT to clarify that the RTA must continue subject to the data available, and remove any misunderstanding concerning the derivation of the RTA when BES awareness has been compromised beyond the reach of the Reliability Standards.