Individual or group. (17 Responses)
Name (8 Responses)
Organization (8 Responses)
Group Name (9 Responses)
Lead Contact (9 Responses)
Question 1 (0 Responses)
Question 1 Comments (15 Responses)
Question 2 (0 Responses)
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Question 4 Comments (15 Responses)

Individual
Thomas Foltz
American Electric Power
AEP agrees with the following comments from the Tech Conference notes (Slide #2, on Decision Authority Responsibility): * Should only be one responsible authority and that is the RC. The RC has wide-area view and ultimately can make the most reliable decisions for their applicable systems. * But TOP needs to protect its lines and RC can't push the 'button'. The TOP & RC must work together and the TOP must have some flexibility in taking actions to protect its own system. * There are times when the TOP must act quickly and coordinate with the RC after the fact (i.e. bad weather/ storm related activities). AEP agrees with the following comments from the Tech Conference notes (Slide #3, on SOL analysis): * Need more clarity on SOLs. There is not consistency among the RC's in establishing an SOL methodology or in the implementation of the methodology. The RC's SOL methodologies are not all inclusive for any facility that has a "rating" but TOPs are responsible for maintaining reliability on all facilities that have operating limits, regardless of whether they meet the RC's SOL criteria. Some SOLs overlap TOP areas and should be planned and operated accordingly. AEP agrees with the following comments from the Tech Conference notes (Slide #4, on Mitigation Plans): * SOL mitigation needs to be simple and easily understood by an operator. Additional clarity could be provided for when an SOL exceedances has occurred (pre or post-contingency). The 30 minute rule of thumb is simple for operators to understand whereas operating above an SOL for "continuous duration" could lead to ambiguities.
AEP agrees with the following comments from the Tech Conference notes (Slide #12 on Reliability Directive): * Need to provide clear guidance to operators on issue of directives – both as issuer and receiver. May need to identify as a Reliability Directive – no questions allowed, jump first and ask questions later as long as the directives do not violate any safety requirements or endanger any equipment. Need make clear for operator to communicate with accuracy and consistency.
AEP agrees with the following comments from the Tech Conference notes (Slide #6 on Unknown Operating State): * If 'unknown' remains, then it needs to be clearly described as to what it means to an operator and clear actions spelled out. If Unknown Operating State does not become a NERC defined term, the requirement should be removed. Otherwise, the industry will continue to struggle with broad interpretation of this requirement.

AEP agrees that the proposed TOP-001-2 and TOP-002-3 standards cover the proposed retirement of requirements from PRC-001-1.
AEP agrees with the fourth bullet from the Tech Conference notes (Slide #14 on Emergency notification). The TOP should notify RC of all Emergencies (based on NERC definition). The TOP and RC continuously coordinate OPA in the operational planning timeframe as well as in real time.
AEP agrees with the second bullet from the Tech Conference notes (Slide #15, Outage Coordination). Requirements inherently include coordination – A valid operating plan cannot be created without coordination. However, AEP would also support continuing the outage coordination concept somewhere in the standards.
If necessary, the topic of secure data exchange methods should be managed within the CIP standards.
Individual
Brett Holland
Kansas City Power & Light
Individual
Jo-Anne Ross
Manitoba Hydro
No comments
No comments
No comments
No comments
No comments
No comments
No comments
No comments
No comments
Individual
Patti Metro
National Rural Electric Cooperative Association (NRECA)
Group
Colorado Springs Utilities
Kaleb Brimhall
None
TOPs should have access to Real Time Contingency Analysis (RTCA), Project 2009-02 needs to move forward to fill this gap. Implementation of RTCA may take time, there are other options, possibly have the RC or BA perform this service.
RC directive should be left for each region to define via their own methodologies for the region.
The unknown state should be left the business practices of each TOP or RC and removed from standard.
PRC-001-1 R2 is applicable to reliability. The important parts of this requirement should be incorporated, as appropriate, into the applicable standards. For example, PRC-004 could incorporate the important aspects/requirements.
This is addressed in the standard EOP-001-2.1b. If the standard language is insufficient in this standard, the recommendation would be to fix it in EOP not add it in TOP/IRO.
* Outage coordination needs a lot of work to be able to fully utilize COS. RC does not currently approve/deny all outages. * Outage coordination methodology should be developed by each RC. Similar to SOL/IROL methodology
This concern should be addressed in the CIP standards under “Information Protection” requirements.
None
Group

Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
NERC proposed the retirement of Reliability Standard IRO-002-2 Requirements R4, R5, R6, and R7, which address real-time monitoring and analysis capabilities and functions required to enable the reliability coordinator to perform its responsibilities. NERC also believes these requirements are unnecessary because they are inherent in the reliability coordinator's duty to maintain area control error or operate within IROLs/SOLs and can be verified in the certification process. Likewise, Southern Company agrees with NERC and believes that there are requirements that require operation within SOLs and IROLs, which are more "results based." It is not practical to have a requirement to measure real-time monitoring nor is this necessary. The real reliability objective is to operate within identified parameters as required in IRO-005-3.1a, IRO-006_EAST-1, IRO-008-1, IROL-009-1, PER-005-1, TOP-001-2, TOP-002-2.1b, TOP-004-2, TOP-007-0, TOP-008-1, VAR-001-3, not to monitor.
No comment.
No comment.
No comment.
No comment.
No comment.
No comment.
No comment.
No comment.
Group
Florida Municipal Power Agency
Frank Gaffney
FMPA agrees with FERC's proposal. By retaining the requirement for TOPs to plan and operate to all SOLs for single contingencies as is required under the existing standards, the system is more resilient to contingencies beyond planning and operating single contingency criteria. SOLs can be set to Emergency Ratings which already take into account loss of life / damage considerations. Without such a requirement, what is to prevent an operator from operating in a condition where a single contingency could result in an Facility exceeding its rating to a degree where its Protection Systems operate automatically, potentially resulting in an unforeseen cascading situation. One of the purposes of PRC-023 is to prevent such automatic operation for single contingencies, but, if the system does not recognize SOLs limited by Facility Ratings, the purpose of PRC-023 can be defeated. TOP-001-2 R8 and references to it should be deleted. TOP-002-3 R2 should also be modified. FMPA does not agree with FERC's concern for single contingencies. FAC-011 makes it clear that SOLs and IROLs established must "provide BES performance" (R2) such that, "(f)ollowing … single Contingencies …, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur" (R2.2). This includes the Most Severe Single Contingency (MSSC). It also includes the time parameters of any associated Emergency Rating. As long as the TOP standards are modified to require TOPs to operate and plan within all SOL and IROLs for single contingencies, then the MSSC is covered. On whether the RC or TOP has primary responsibility for IROLs, the answer may depend on whether it is pre-contingency or post-contingency. Pre-contingency, e.g., a current day, next day or next hour analysis indicates that an IROL may be exceeded, the RC would have primary responsibility. Post-contingency where an IROL may have been exceeded as a result of multiple contingencies, FMPA would expect the TOP to react immediately in correcting the situation since time is quite short for correcting, and coordinate with the RC as time permits. FMPA agrees with the Commission's proposal to retain the requirement of the RC to monitor all SOLs. The TOP is accountable to managing SOLS; however, the RC should be responsible to monitor the performance of the TOP in performing their responsibilities.

Generally, FMPA agrees with the Commission's proposal. FMPA believes that there ought to be recognition somewhere in the standards of multi-contingency events for which limits are not established. Although FAC-011 and FAC-014 provide for establishing limits for single and selected double contingencies, they do not provide for multiple contingencies that could occur in the operating horizon, e.g., loss of ROW, loss of substation, etc., which are beyond operating and planning criteria and will likely result in an "unknown operating state" where the operators will not know what the next single contingency will cause from a stability / voltage stability viewpoint (thermal should be known from real time contingency analysis). There ought to be a requirement somewhere for someone to figure out what is going on and take action within a specified amount of time.
In general, FMPA agrees with the Commission's proposal. FMPA believes that TOP-003-2 lacks sufficient detail to determine the minimum amount of data and information required for reliable operation. As we have stated in past comments, we believe that TOP-003-2 ought to specify the minimum acceptable "data specification".
FMPA agrees with FERC's proposal, TOP's should inform the RC (and other impacted TOPs) of all Emergencies regardless of the operating time frame, and the standard should be clarified to say as much. In addition, the term "Emergency" should be used, not "Adverse Reliability Impact", so that it synchronizes with the definition of Reliability Directive and to avoid ambiguity.
FMPA agrees with the Commission's proposal to retain the requirement of the RC to coordinate outages. Although proposed IRO-002-3 provides the RC the authority to cancel planned outages; the standard suffers from two primary issues: (i) the same problem as question 5 above in that IRO-010 is not specific enough to know how far in advance entities must submit their maintenance plans; and (ii) IRO-002-3 lacks sufficient detail to assure a not unduly discriminatory or preferential treatment of planned outages, as required by FPA Section 215 (d)(2). Coordination of outages, including generator outages, must be done in advance to assure a fair and equitable process in addition to assuring reliability.
Although not raised by the Commission, FMPA continues to believe that Unit Commitment, an important activity of reliable operation, will be removed from the standards with the proposed TOP/IRO standard revisions. The current BAL standards do not have a requirement for the development of a next day operating plan, as is currently required of the BA in TOP-002-2 R4. FMPA interpreted TOP-002-2 R4 as requiring the BA to have a next day operating plan that at minimum would include a plan for Unit Commitment. The proposed TOP-002-3 R1 removes the BA as an applicable entity, causing the removal of Unit Commitment requirements from the standards. In past comments, the SDT maps this BAL-002, which is incorrect since BAL-002 is real-time, not next day. It also points to BAL-001 on ACE, but, again, the requirements of BAL-001 are either real-time or 12 month rolling average which is not next day Unit Commitment. In response to comments, the SDT claims we have confused the role of the BA with the LSE; however, FMPA believes the SDT is confused. Unit commitment is to be planned by the BA, i.e., page 32 of the Functional Model, in describing the responsibilities of the BA, is to: "5. Formulate an operational plan (generation commitment, outages, etc.) for reliability evaluation." Such responsibility that is important to the reliable operation should be within the standards. In addition to the reliability gaps identified by the Commission, FMPA believes this to be another reliability gap created by the proposed standards.
Group
Duke Energy
Michael Lowman
(1) Duke Energy believes that a common conceptual interpretation of an SOL for the Operation Planning and Real-time time horizons is needed in order to establish the foundation for the TOP/IRO standards and requirements. Currently, there is no consistent interpretation of an SOL throughout the industry. These multiple interpretations adds to the difficulty in applying a consistent approach to the definition of an SOL moving forward. (2) Duke Energy believes a TOP/RC operating in real-time with pre-contingency or post-contingency IROLs should develop and implement a mitigation plan that would mitigate the condition within 30 minutes. However, for instances where a potential SOL could be exceeded following a contingency, a TOP/RC's mitigation plan should be developed that could be implemented in real-time within 30 minutes post-contingency.

(1) Duke Energy believes that NERC Functional Certification is enough to satisfy the Commission's concerns .
(1) Duke Energy believes that Operating Instruction during an Emergency is unclear, vague, and subject to interpretation. By using the NERC defined term of Emergency, certain tasks that Duke Energy believes is a non-emergency action would now be considered an Emergency and subject to zero tolerance. Duke submits, for consideration by the SDT, a revised definition of Emergency in an attempt to remove this ambiguity. Emergency – Any abnormal system condition that requires automatic or immediate manual action to prevent the failure of transmission facilities or generation supply that would adversely affect the reliability of the Bulk Electric System. We continue to believe that if all instances of communication from an RC/TOP to a BA, TOP, GOP, etc. is considered a directive, then it could dilute the importance of real-time emergency situations that could be dangerous for the BES. Creating and implementing a term such as Reliability Directive would actually heighten situational awareness among Entities rather than decrease it as stated by the Commission. In addition, Duke Energy believes that maintaining the language in R1 of TOP-001-2 and adding, "each Reliability Directive issued and identified as such by its Transmission Operator(s) or Reliability Coordinator, unless such action would violate safety, equipment, regulatory, or statutory requirements." as part of this requirement would provide the clarification needed by a real-time System Operator.
(1) Duke Energy is not opposed to the removal of the term "unknown operating state" from the proposed standards based on the conclusion that the term itself is essentially undefined and is interpreted differently around the industry. We feel that the idea of an "unknown operating state" is too broad in scope to be able to narrow down to a common industry definition. If a term can and is interpreted differently by each entity, it becomes more difficult to measure compliance to a standard that is based on subjectivity.
(1) Duke Energy believes that the proposal to retire certain requirements should be revisited. We are not convinced that the proposed TOP-002-3 prescribes the necessary corrective action. With that said, if PRC-001 is to remain enforceable, we suggest that a project be initiated to re-word the standard. As is written now, the wording of PRC-001 is too broad and is problematic. The phrase "reduces system reliability" as used in R2.2 and R2.3 of the currently enforceable standard is particularly broad, and should be a candidate for clarification. Lastly, if PRC-001 is to be retired, the SDT should consider revising the proposed standards to include more adequately what will be removed by PRC-001's retirement.
(1) Duke Energy is not opposed to the intent of the notification by the TOP to an RC under certain conditions. We feel that if a TOP is re-configuring and/or re-dispatching its system, that this condition would not warrant notification to an RC. However, when a TOP decides to initiate its Emergency Plan, the TOP should notify the RC of the decision. Also, we suggest that the time horizon be limited to Current Day and Next Day. We would not be supportive of a time horizon beyond Next Day.
(1) Duke Energy believes that outage coordination is an integral part of the reliability of the BES. Based on that potential impact to the BES, we believe that outage coordination should be a coordinated effort between the TOP, its RC, and affected RC(s) and explicitly addressed in the standards.
(1) Duke Energy agrees that the exchange of data should be initiated on a secure network. We believe that the SDT should review the current reliability standards, CIP and COM, as well as Standards Project 2009-02, Real-time Monitoring and Analysis Capabilities to determine if this issue has already been addressed or will be addressed in the future.
Group
Peak Reliability
Vic Howell
IROL Versus SOL Monitoring: While the determination of the existence of an IROL should be a collaborative effort between the RC and TOPs, the RC should have primary responsibility for monitoring and implementing mitigation for IROLs, while TOPs should have primary responsibility for monitoring and implementing mitigation for other SOLs. However, since any part of the BES could become an "IROL condition" as system conditions degrade, it is very difficult to draw a bright line between what the TOPs should be responsible for monitoring versus what the RCs should be

responsible for monitoring. Operating Within All SOLs: TOPs should operate within all SOLs – not just a subset of SOLs. The SDT should consider changing the standard. But even the very concept of “operating within all SOLs” means different things to different entities. SOL Confusion: There is much confusion with – and many widely varied interpretations and applications of – the SOL term. If there are inconsistencies with the interpretation and application of the SOL term, then logically, there will be inconsistencies with the notion of “establishing SOLs”, “operating within SOLs”, and “exceeding SOLs” as referenced in the Reliability Standards. Each TOP and RC may have a different idea of what it means to establish SOLs, to operate within SOLs, and to exceed SOLs. This wide variance in interpretation of the SOL concept needs to be addressed in the Reliability Standards. While some entities have suggested that the RC SOL Methodology may be able to address this, Peak believes that it is important to have NERC-wide consistency on this issue, and that the Reliability Standards are the most appropriate mechanism for that consistency. Most Severe Single Contingency: TOP-004-2 R2 states: “Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.” While the proposed language in the revised TOP standards only addresses pre-determined IROLs, TOP-004-2 R2 addresses adverse operating states for which there may be no pre-determined IROL. Removing this requirement could result in decreased reliability. Although duplication of requirements should be avoided in Reliability Standards, it is important to reliability that the Reliability Standards address both pre-determined IROLs as well as operating states where the most severe single contingency could result in Adverse Reliability Impacts. This could be addressed by either retaining the TOP-004-2 R2 language or modifying language in the proposed standards. TOP-004-2 R2 is actually better for reliability than other Reliability Standard requirements to establish and operate within IROLs. The IROL concept is “how” RCs and TOPs achieve the ultimate reliability objective (the “what”) described in TOP-004-2 R2.
A TOP cannot have true situational awareness without the awareness that tools like RTCA provide. All TOPs should know if their TOP Area is demonstrating acceptable post-contingency system performance. This will require all TOPs to have tools that have, at least, the same or similar capability as RTCA. Otherwise, there may be facilities that are not monitored for post-contingency performance, which is a significant reliability gap. Even in cases where the RC uses RTCA, the TOP must maintain primary responsibility for monitoring performance in their system. Peak Reliability would like to see the NERC Reliability Standards somehow address this significant reliability issue.
Peak agrees with the NOPR, that following Reliability Directives should be mandatory at all times, not just in cases of emergencies (or Emergencies) or Adverse Reliability Impacts. The NERC definition of Reliability Directive should be adjusted accordingly. Peak also agrees with the notes that a Reliability Directive must be identified as such in real-time in order to clearly delineate between conversations about potential actions and the actual mandatory actions associated with a Reliability Directive. Peak Reliability agrees with the technical conference notes that the NERC definition of Emergency “is broad and covers a lot of conditions –and no easy way to know when you have transitioned from normal to Emergency.” It may be beneficial to revisit the definition of Emergency.
The SDT should define "unknown operating state". If this term is not defined, then it should not be used in Reliability Standards. The parenthetical words in TOP-004-2 R4 describing an unknown operating state, “(i.e. any state for which valid operating limits have not been determined)” does not clarify the issue, but rather leads to more questions and confusion.
TOPs should be required to take action when acceptable pre- or post-contingency system performance is not happening in real-time. If the Reliability Standards are not clear on this issue, changes should be made such that this expectation is clear.
Peak Reliability agrees that the notification should not be limited to day-ahead, but should also occur as necessary in Same-Day and Real-time horizons.
Outage coordination is arguably one of the widest, most risk laden reliability gaps in the Reliability Standards. Outage Coordination expectations need to be clarified and fully addressed in the NERC Reliability Standards. RC and TOP roles and responsibilities need to be clarified. Outage Coordination is addressed in many parts of North America via tariffs, etc., so it may not be a reliability gap for some. However, the Reliability Standards should not depend on the existence of tariffs to address significant reliability issues such as outage coordination – it should be addressed in the Reliability Standards The current Reliability Standards simply do not adequately address it. Potential solution would be to create a Reliability Standard that: 1)Requires the RC to establish and document an outage coordination process for the RC Area, 2)Requires the RC’s outage coordination process

document to address a specific list of issues (much like the new MOD-001-2 R1 concept), and 3)Requires TOPs and BAs within the RC Area to follow the RC's outage coordination process.
Many of the issues surrounding the TOP/IRO efforts here are rooted in SOL and IROL concepts – operating within some SOLs but not others, delineation of responsibility between SOLs and IROLs, etc. The St. Louis and Washington DC TOP/IRO technical conferences revealed the inconsistencies and industry confusion with these terms. Considering the wide disparity and inconsistency with the use and application of the SOL and IROL terms, it is strongly suggested that the industry revisit these terms. Results Based Reliability Standards – as quoted from NERC's website: "Results based standards are standards that focus on required actions or results (the "what") and not necessarily the methods by which to accomplish those actions or results (the "how")." The SOL and IROL concept are in direct conflict with the Results Based approach. According to FAC-011-2 R2, an SOL/IROL is intended to provide a certain level of BES system performance. The SOL/IROL is the method by which ("how") acceptable system performance ("what") is achieved in real-time operations. It is a means to an end – not the end itself. "How" a TOP or RC accomplishes that reliability objective is directly determined by the tools (real-time tools or lack thereof) employed by those entities. Despite the fact that the Reliability Standards are heavily invested in the SOL and IROL terms, the relevance of these terms needs to be reevaluated, or at the very least revisited, both in definition and their use in the Reliability Standards. Doing so would result in 1) more clarity and consistency across the industry, 2) a more streamlined operational approach to achieving the ultimate reliability objective of acceptable system performance, and 3) a compliance approach that is more aligned with the Results Based concept endorsed by NERC.
Individual
Bill Fowler
City of Tallahassee
TAL agrees with the Commission's proposal in part. Many IROLs are identified for multiple conditions. While an SPS may be provided to enable controlled separation or automatic action to minimize the operators task loading, it should be clarified that the system need only be operated in real time to N-1 (and credible double) contingencies. To require operation to every conceivable IROL would unnecessarily limit use of the BES for emergency and commercial purposes. Clarity is also needed in determining "how far do we go" in determining SOL/IROLs. Any system will end up in trouble when multiple contingencies are considered. The key will be to determine what the next N-1 scenario is and prepare for it. A pre-defined IROL should not be required for a system that only shows "instability/uncontrolled separation or cascading outages" when several contingencies are stacked up. A reasonable expectation needs to be made clear and unambiguous.
While TAL agrees with the Commission, care should be taken to avoid requiring small BA/TOPs from having to obtain a Real Time CA program. Many of the entities have used the adequate modeling of the system by the RC to enable the RC to monitor the smaller system since it is not an impact to the majority of the RC Area. This practice should be allowed to continue.
TAL realizes this is a contentious area. The industry has never shown a reluctance to follow directives from the RC or a TOP. The area of concern is exposing ALL communications to be subjected to the same level of scrutiny by Compliance when there is no consideration if the action was carried out! The only concern is was 3-way communication used. If the action MUST be carried out, call it what it is, a Directive. IF there is room for negotiation, negotiate and take the proper action for the reliability of the BES. Many companies require a Directive to operate out of economics for a reliability issue in another TOPs area.
TAL believes the unknown operating state can exist during those periods that the RC's Contingency Analysis tool does not solve. If CA is solving, the state of the BES in "known". It may show some high overloads and low voltages, but it generally indicates that instability/ uncontrolled separation or cascading outages will not occur. Specific operating limits for every conceivable scenario are not necessary and do not add clarity if we are only operating to N-1 (and credible doubles). The TPL studies are good tools to be aware of what may occur, and to build certain projects, but are of little value to the real-time operation of the BES.
No comment
TAL concurs with the Commission.

TAL agrees with the commission, but not with the Independent Experts Report. Coordination of both Transmission and Generation should occur, but 36 months is excessive. Many entities do not plan that far in advance (with the exception of Nuclear Facilities). While some do plan that far in advance, they are primarily for budget purposes (major vs. minor overhaul) or to ensure vendor support/contractor schedules are coordinated. Requiring the RC to approve these at the 36 month window is an unnecessary burden on the RC with no value added to the operation of the BES. The outages do need to be coordinated as they approach the next day studies. Forced outages may affect the starting of an outage, but once you tear into a turbine, it is down for the duration of the outage.
No comments
No comments
Group
ACES Standards Collaborators
Jason Marshall
(1) While we agree with the concept of planning and operating the system within all SOLs and IROLs, the primary issue is that not all SOLs are created equal and if not implemented properly this blanket statement could reduce operational flexibility. FAC-011-2 R1.2 states that SOLs cannot exceed Facility Ratings. This creates ambiguity and confusion for operating within all SOLs. Does this mean that an SOL cannot exceed a continuous rating? If so, then the operator cannot take advantage of short-term ratings. We believe there needs to be some clarification in the FAC-011-2 standard along with the TOP standards to make it clear that exceeding a Facility Rating is not an SOL violation if the System Operator is utilizing a short term rating. (2) We agree with the concept that the RCs have primary responsibility for the reliability of the Bulk Electric System which is typically accomplished by monitoring the limits of SOLs and IROLs and in market operations directly controlling generation dispatch. In addition, we also agree that TOPs have primary responsibility for monitoring and controlling the limits of SOLs. We also agree with the technical conference comments that TOPs need to work with RCs to accomplish this task. However, this does not mean that all coordination and responsibilities need to be documented in requirements. Some could be documented in supporting documents. In many cases, RC does not have the capability or the tools to operate facilities. The TOP has this capability. In all cases (SOL, IROL) the RC should be responsible to ensure the reliability of the BES. In practice, this does not mean that the TOP will never respond to IROLs and it does not mean that the RC will not respond to SOLs. The TOP response could be included in the RC operating plans for responding to IROLs. Perhaps, the RC responsibility for SOLs would begin when certain situations arise, such as when the TOP calls upon the RC for assistance, the TOP does not respond satisfactorily to system conditions, or the SOL affects more than one TOP. There should be clear delineation of responsibilities and we recommend including examples in the technical guidance sections of the standard. (3) Because the standards already require the TOP to plan to operate within all SOLs, the standards already require the TOP to plan to operate within the most severe single contingency. A close look at the FAC standards make this clear. FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that is consistent with the established Reliability Coordinator SOL methodology. FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and stability limits while demonstrating that the BES remains stable during pre-contingent (Requirement R2, part 2.1) and post-contingent (Requirement R2, part 2.2) conditions. Requirement R2, part 2.2 would also cover the most severe single contingency. FAC-014-2, Requirement R6 compels the Planning Coordinator to identify which multiple contingencies that would result in exceedances of stability limits and to communicate the list of multiple contingencies along with the stability limits to the Reliability Coordinator. FAC-011-2 further compels the Reliability Coordinator to establish a process for identifying which stability limits associated with multiple contingencies identified by the Planning Coordinator are applicable in the operating horizon within its SOL methodology. FAC-014-2, Requirement R5, part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider. FAC-014-2, Requirement R5, part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities. Finally, the contemplated changes to proposed TOP-002-3, Requirement R2 will require the Transmission Operator to operate within SOLs. Thus, the combination of proposed TOP-002-3, Requirement R2, FAC-011-2, and FAC-014-2 cover the most severe single contingency and more.

(1) We disagree that there should be an explicit requirement to have specific tools. Requiring specific tools applies a one-size fits all approach that could have significant financial impacts on small entities. Standing up and maintaining advanced EMS functions such as real-time contingency analysis (RTCA) capability can be quite expensive for a small TOP. While we would agree that all large TOPs should have real-time contingency analysis (RTCA) capability, we question the need for RTCA capability for all small TOPs. If a small TOP is wholly contained within a large TOP and the large TOP can see into its system with it RTCA, is it really necessary for the small TOP? Furthermore, why can't the small TOP rely on its RC's RTCA results? The small TOP may also have few enough contingencies that it could complete a comprehensive deterministic study of its transmission system by enumerating all contingencies in the study so that it knows exactly what the operational impacts would be. (2) We disagree with the technical conference comments that relying on the certification process is problematic and that certification is weakened by removing requirements to have tools. If a TOP is required to operate within all SOLs, they must have the tools to determine they are operating within SOLs. When they are certified, this capability must be verified otherwise the certification process has failed. Section IV.4 of Appendix 5A – Organization Registration and Certification Manual of the NERC Rules of Procedure requires the TOP to be recertified for significant changes such as a change in footprint, relocation of a control center or replacement of an EMS. Thus, certification is designed to remain current with the TOP's capabilities. The bottom line is that if the TOP does not have the tools to give it the capability to operate within SOLs it will not. (3) Contrary to the feedback provided in the technical conference notes on slide 9, we disagree with the need for a TOP to know the cause of an SOL violation in order to act. If a TOP has a transmission line with a generator at one end and the flow on the line is exceeding the SOL, the TOP does not need to know the cause to know that redispatching the generator will mitigate the SOL. Now, the TOP may want to investigate the cause after it has mitigated the SOL violation to prevent the problem from being exacerbated further but they do not and should not wait to act until they know the cause.
We have no additional comments than those raised in the technical conference and believe the issues were captured appropriately.
(1) We do not believe it is necessary to have an explicit requirement to move from an unknown operating state to secure state because the situation would be rare, measuring compliance with such a requirement is challenging, and its covered (or will be after changes to the standards) by the requirements to operate within all IROLs and SOLs and to return they system within SOL and IROL limits. Furthermore, we believe that when a system enters an unknown operating state it is likely due to a lack of extensive study of the system and the state likely could have been known if studied. An IROL should establish boundaries of a known operating state and it should be rare to have a situation where a pre-determined IROL does not exist and the operation of the transmission system is pushed into an IROL. If the system is well studied, all IROLs should be identified. If loss of telemetry is considered an unknown state then it would be even more difficult to move to a "known" state since you cannot see into the system.
We have no additional comments than those raised in the technical conference and believe the issues were captured appropriately.
(1) We do not see significant differences between what the Commission proposed (i.e. to require the TOP to notify the RC of all emergencies regardless of time frame) and what the drafting team proposed. The primary difference seems to be in the use of Adverse Reliability Impact versus Emergency. The technical conference notes seem to capture these minor issues caused by the differences.
(1) We agree that there may not be an explicit requirement to implement an outage coordination process, however from a practical perspective it is implicitly required. First, the Operational Planning Analysis might identify a conflict that could cause an expensive cancellation of an outage. For this reason, the TOP and RC will have processes to evaluate outages further out. Secondly, the TPL standards also include a requirement (e.g. TPL-002-0b R1.3.12) to include planned maintenance. If the drafting team determines the need to add requirements for outage coordination, they should be careful to avoid creating redundancies to avoid violating P81 criteria.
(1) We believe this is an issue that should be covered by the CIP standards. It should not be covered separately in the TOP standards.
We have no additional comments. Thank you for the opportunity to comment.

Group
SPPRE
Bob Reynolds
SPPRE shares the same concerns as FERC.
There needs to be close coordination between Project 2009-02 (Real Time Reliablity Monitoring and Analysis) and the TOP/IRO Revisions project. Currently the NERC website indicates that Project 2009-02 is scheduled to be completed by 1/1/15 in line with the completion date of the TOP/IRO revisions. If these two efforts are coordinated, project 2009-02 should address the concerns expressed by FERC.
Defining both terms may reduce ambiguity
The term "unknown operating state" is ambiguous and many entities find it hard to describe what it is. There may be other ways to word the standard that address FERC's concern that are clearer.
Without a standard entities may not take corrective actions on their own.
All emergencies should be communicated between the TOP and RC.
Outage coordination needs to be included.
"via a secure network" is better addressed by the CIP Standards.
Individual
Scott Langston
City of Tallahassee
TAL agrees with the Commission’s proposal in part. Many IROLs are identified for multiple conditions. While an SPS may be provided to enable controlled separation or automatic action to minimize the operators task loading, it should be clarified that the system need only be operated in real time to N-1 (and credible double) contingencies. To require operation to every conceivable IROL would unnecessarily limit use of the BES for emergency and commercial purposes. Clarity is also needed in determining “how far do we go” in determining SOL/IROLs. Any system will end up in trouble when multiple contingencies are considered. The key will be to determine what the next N-1 scenario is and prepare for it. A pre-defined IROL should not be required for a system that only shows “instability/uncontrolled separation or cascading outages” when several contingencies are stacked up. A reasonable expectation needs to be made clear and unambiguous.
While TAL agrees with the Commission, care should be taken to avoid requiring small BA/TOPs from having to obtain a Real Time CA program. Many of the entities have used the adequate modeling of the system by the RC to enable the RC to monitor the smaller system since it is not an impact to the majority of the RC Area. This practice should be allowed to continue.
TAL realizes this is a contentious area. The industry has never shown a reluctance to follow directives from the RC or a TOP. The area of concern is exposing ALL communications to be subjected to the same level of scrutiny by Compliance when there is no consideration if the action was carried out. The only concern is was 3-way communication used. If the action MUST be carried out, call it what it is, a Directive. IF there is room for negotiation, negotiate and take the proper action for the reliability of the BES. Many companies require a Directive to operate out of economics for a reliability issue in another TOPs area.
TAL believes the unknown operating state can exist during those periods that the RC’s Contingency Analysis tool does not solve. If CA is solving, the state of the BES in “known”. It may show some high overloads and low voltages, but it generally indicates that instability/ uncontrolled separation or cascading outages will not occur. Specific operating limits for every conceivable scenario are not necessary and do not add clarity if we are only operating to N-1 (and credible doubles). The TPL studies are good tools to be aware of what may occur, and to build certain projects, but are of little value to the real-time operation of the BES.
TAL concurs with the Commission.
TAL agrees with the commission, but not with the Independent Experts Report. Coordination of both Transmission and Generation should occur, but 36 months is excessive. Many entities do not plan that far in advance (with the exception of Nuclear Facilities). While some do plan that far in advance, they are primarily for budget purposes (major vs. minor overhaul) or to ensure vendor

support/contractor schedules are coordinated. Requiring the RC to approve these at the 36 month window is an unnecessary burden on the RC with no value added to the operation of the BES. The outages do need to be coordinated as they approach the next day studies. Forced outages may affect the starting of an outage, but once you tear into a turbine, it is down for the duration of the outage.
Group
Bonneville Power Administration
Andrea Jessup
None.
None.
BPA recognizes that while “directives” from either the TOP, RC or BA where action by the recipient is required to address emergency or adverse reliability impacts is imperative during operational emergencies, having the ability to communicate freely and comment during non-emergency and normal operating times without being bound by compliance, or having to act immediately to a specific set of instructions allows operators the sovereignty to make the best informed decision to the exact conditions of the system. BPA strongly believes that to confine all communications between parties to be strictly perceived as directives is disadvantageous, greatly reduces the ability to communicate and suffers reliability.
BPA recognizes that an unknown operating state can exist when elements are out of service and studies have to be re-established for new known limit(s). Though the removal of the term “unknown operating state” may be beneficial from a monetary perspective, BPA believes that the term “unknown operating state” is best for reliability and should be clearly defined. BPA also believes that at the moment when an element is out of service is when the “unknown operating state” begins – not after a determination has been made.
None.
None.
None.
None.
None.
Group
SPP Standards Review Group
Robert Rhodes
Regarding who’s responsible for IROLs, the RC is responsible for IROLs but the TOP should not stand back and wait for the RC to direct action on the part of the TOP. It’s a coordinated effort between the RC and TOP. To help clarify the lines of responsibility, we suggest returning the language from TOP-007-0, R4 to the proposed TOP-001-2, R10. We believe the near-IROLs should be eliminated. We should restrict ourselves to IROLs and SOLs only.
There needs to be close coordination between Project 2009-02 and the TOP/IRO Revisions project. Currently, the NERC website indicates that Project 2009-02 is scheduled to be completed by January 31, 2015 in line with the completion date of the TOP/IRO Revisions project. If these two efforts are coordinated, Project 2009-02 should address the concerns expressed by FERC.
With all the prior discussion surrounding COM-003-1 which has now morphed into COM-002-4 including the loss of the term Reliability Directive, we are a little confused as to which way to go. Some are in favor of moving on with the term Operating Instruction while others see merit in maintaining Reliability Directive. Whichever, the TOP/IRO Revisions effort needs to be closely coordinated with the Project 2007-02 effort.
The term ‘unknown operating state’ is a very ambiguous term that is so open ended, how do you ever get a handle on identifying what it really is? We suggest that we define the term within very strict criteria or eliminate it altogether.
The requirement in PRC-001-1, R2 specifically includes taking corrective action to resolve the issue but neither TOP-001-2, R5 nor TOP-002-3, R1 include taking action. The proposed requirements

require a plan and the distribution of that plan to those impacted entities but does not mention taking action to address the situation. Perhaps we simply need to incorporate that language into the requirements.
Perhaps the best thing to do in this situation is to combine R3 and R5 and specifically clarify that this crosses all time horizons. Combination was suggested at one of the conferences.
We tend to lean toward FERC's position on this topic in that previously outage coordination was right out front. With the references now wrapped up in data exchange, the coordination effort itself is somewhat obscured.
We concur with the comment from one of the conferences which asked if this wasn't a CIPs issue. If you're compliant with the CIPs standards aren't you already addressing this concern? Also, as proposed in one of the conferences, perhaps security experts should be consulted to review this issue.
Thank you for the opportunity to comment on the proceedings of the technical conferences.
Individual
Christina Conway
Oncor Electric Delivery Company LLC
In an effort to evolve to results-based Reliability Standards, Oncor encourages the SDT to address real-time reliability monitoring and analysis capabilities by defining the results ("what") Entities are mandated to meet, and let the Entity define the "how" they meet the requirements since there is not a "one size fits all". For example, allowing the Entity to determine "how" they use their RTCA tools.
In an effort to include planned switching activities, Oncor recommends the following: A communication initiated by an RC, TOP, or BA where action by the recipient is necessary to address an Emergency, Adverse Reliability Impacts, and actions to maintain system reliability.
In an effort to evolve to results-based Reliability Standards, Oncor promotes alignment of basic functions to support the reliability of the BES. Oncor recommends any requirements regarding "secure networks" should be aligned to Communications Network Reliability Standard developed under Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions.
Individual
Michael Moltane
ITC
The Commission's proposal to treat all non-IROL SOLs as though they were IROLs for the purposes of reporting and mitigation is simply too severe, will cause undue burden, and is unnecessary to maintain the reliability of the Bulk Electric System. The Commission is absolutely correct to observe that, "if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter." Furthermore, Requirement R2 of this Standard permits each Transmission Operator to designate non-IROL SOLs for IROL treatment where the Transmission Operator deems it necessary for internal area reliability. No one is better positioned than the Transmission Owner to determine precisely which, if any, SOLs are important to internal area reliability, and Transmission Operators are more than sufficiently motivated to ensure that their system is not the source of an SOL which results outages that are significant but do not reach the threshold of an IROL (such as impacting a major sporting event, etc.). To be clear, ITC is fully supportive of Transmission Operators continuing to monitor all SOLs and for Transmission Operators to maintain mitigation plans for all SOLs; the proposed standards should be revised to reflect this. However, despite the contribution of non-IROL SOLs to the Northeast Blackout of 2003 and the 2011 Southwest Outage, ITC believes that treating each SOL as IROL will create a significant burden on the Bulk Electric System resulting from the significant amount of additional infrastructure necessary to meet such a requirements while maintaining the current level of service for customers in terms of both cost and availability. Such a requirement

would also impose a substantial additional compliance burden on registered entities without realizing a commensurate improvement in the reliability of the Bulk Electric System. Simply put, the proposal to treat all SOLs like IROLs will result in a significant increase in pre- and post-contingent load shedding, uneconomic dispatch, and reconfiguration of the Bulk Electric System until additional facilities can be put into place to meet the requirements. Transmission Operators must be given the discretion to define an appropriate mitigation strategy for each SOL reflecting the particular reliability issues associated with that SOL. Doing so would achieve the reliability gains of the Commission's proposal, but without the massively increased burden on consumers and registered entities which would result from a one-size-fits-all approach. Regarding NOPR Paragraph 87 in which the FERC asks for clarification regarding roles of the RC and TOP for IROLs, ITC believes the decision making authority for IROL's should clearly be with the RC. The TOP should coordinate with the RC as mandated by TOP-001-2 R10. The TOP should be responsible for SOLs. TOP-001-2 R 11 should be modified to clearly indicate that IROL decision making authority and responsibility lies with the RC.
ITC supports the tech conference comments that unknown state shall be defined clearly if the requirements are retained.
ITC supports the NOPR concept that the TOP should inform and coordinate with the RC on all IROL and SOL violations for all operations time horizons.
ITC agrees that since RC has the wide area view, RC should have the authority to coordinate transmission and generation outages across TOP, BA and adjacent RCs.