Consideration of Comments on Real-Time Operations — Project 2007-03

The Real-Time Operations SAR Drafting Team thanks all commenters who submitted comments on the 4th draft of the standards for Real-Time Operations – Project 2007-03. These standards were posted for a 30-day public comment period from August 4, 2010 through September 3, 2010. Stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 34 sets of comments, including comments from more 34 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

The SDT made a number of changes to requirements and measures based on industry comments and additional changes based on observations of a Quality Review team. Where a changes was made to a requirement, conforming changes were made to the associated measure and VSLs.

TOP-001-2:

- Requirement R2– added the word 'identified' to make it clear that it is only "identified Reliability Directives" included in the scope of the requirement. Added "Operations Planning" as an additional possible time horizon.
- Requirement R3 – changed 'of' to 'by' to correct a typographical error.
- Requirement R5 – changed 'coordinate' to 'inform;' changed 'coordination' to 'communications;' and replaced 'with those Transmission Operators' with 'those respective' for simplification.
- Requirement R6 – changed 'coordination' to 'notify;' added a phrase to be more specific about what functional entity to notify; changed 'telemetering' to 'telemetry' for clarity.
- Requirement R8 – changed 'local' to 'internal' to clarify that the scope is limited to the TOP's own area.
- Requirement R9 – changed the VRF from "high" to "medium."
- Requirement R11 – added a 30 minute constraint on the time to respond to an SOL supporting the TOP's internal reliability.
- Deleted Requirements R12 – R14 as these requirements related to facility capabilities and will now be addressed in a separate project. (Project 2009-02 Real-time Monitoring and Analysis Capabilities
- Added an explanation to justify the VSLs for R5.

TOP-002-3:

- Purpose – updated to more closely align with the requirements in the standard
- Updated the text box associated with Requirement R1 to clarify the expectation that the Operational Planning Analysis is required under all conditions.
- Requirement R2 - changed 'local' to 'internal' to clarify that the scope is limited to the TOP's own area.
- Requirement R3 – changed 'reliability' entity to 'registered entity' for additional clarity.
- Added an explanation to justify the VSLs for R3.

TOP-003-2:

- Requirement R1 – changed ‘have’ to ‘create’ for clarity; changed ‘equipment’ to ‘facilities;’ removed the language specifying that the outage information comes from the Transmission Operator or Balancing Authority.
- Requirement R4 – added the Transmission Operator as one of the entities that must provide requested data.
- Requirement R5 – merged into Requirement R4.
- Measures M2 and M3 – added web postings with acknowledgment as additional examples of acceptable evidence.
- Eliminated redundancies in VSLs for R2.

The SDT recommends that this project be moved forward to the balloting stage.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 315-439-1390 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X
2.	Group	Kenneth D. Brown	Public Service Enterprise Group Companies	X		X		X	X				
3.	Group	Brent.Ingebrigtson@eon-us.com	E.ON U.S.	X		X		X	X				
4.	Group	Marie Knox	Midwest ISO Standards Collaborators	X									
5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
6.	Group	Sandra Shaffer	PacifiCorp	X		X		X					
7.	Group	Mike Hardy	SERC OC Standards Review Group	X		X		X					
8.	Group	JT Wood	Southern Company Transmission	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				
10.	Group	Louis Slade, Jr.	Dominion	X		X		X	X				
11.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X
12.	Group	Patrick Brown	PJM		X								
13.	Group	Ben Li	IRC Standards Review Committee		X								
14.	Group	Steve Rueckert	Western Electricity Coordinating Council										X
15.	Individuals	L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson			X								
16.	Individual	Dan Rochester			X								
17.	Individual	Joylyn Faust				X	X	X					
18.	Individual	John Fish						X					
19.	Individual	Jonathan Appelbaum		X									
20.	Individual	Kasia Mihalchuk		X		X		X	X				
21.	Individual	Jon Kapitz		X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Howard Rulf				X	X	X					
23.	Individual	RoLynda Shumpert		X		X		X	X				
24.	Individual	Greg Rowland		X		X		X	X				
25.	Individual	Michael Lombardi		X		X		X					
26.	Individual	Leland McMillan		X		X		X					
27.	Individual	Richard Kafka		X		X		X	X				
28.	Individual	Saurabh Saksena		X		X							
29.	Individual	Randi Woodward		X									
30.	Individual	Darryl Curtis		X									
31.	Individual	Catherine Koch		X									
32.	Individual	Terry Harbour		X									
33.	Individual	Jason Shaver		X									
34.	Individual	Michael Gammon		X		X		X	X				

1. TOP-001-2: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: As shown below, the SDT made a number of changes to requirements based on industry comments. All changes were semantic to provide additional clarity.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

R5. Each Transmission Operator ~~and Generator Operator~~ shall ~~coordinate~~ inform other Transmission Operators of its ~~respective~~ operations known or expected ~~by the Transmission Operator~~ to ~~have~~result in ~~a reliability impact~~ an Adverse Reliability Impact on ~~the portion of the BES of other~~ those respective ~~reliability entities~~Transmission Operator Areas with those ~~entities~~ Transmission Operators unless conditions do not permit such ~~coordination~~communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load,

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 within 30 minutes.

M5. Each Transmission Operator shall make available upon request, evidence that ~~operations~~ it ~~coordinated~~ informed other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas ~~with those Transmission Operators~~ in accordance with Requirement R5 unless conditions did not permit such ~~coordination~~ communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M8. Each Transmission Operator shall make available evidence that it has informed it~~'~~s Reliability Coordinator of each SOL~~s~~ which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
Public Service Enterprise Group Companies	No	In R1 the word "identified" was added as an adjective to describe "Reliability Directive." While this is a step in the right direction, it needs further clarification. The requirement should be further modified to indicate that the Transmission Operator must indentify. i.e., state that "this is Reliability Directive" to ensure that the entities that must comply with this requirement know that what is being communicated by the TOP is a Reliability Directive and not some other less urgent communication.
Response: "Reliability Directive" is not meant to equate to the urgency of a situation; rather it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views a Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to affect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made.		
E.ON U.S.	No	E.ON U.S. suggests that in the definition of directive the adjective "mandated" should be added and placed in front of "action."
Response: Revision to the definition is not in the scope of this standard. The Definition of Terms for TOP-001-2 states the "…definition (of Reliability Directive) is included here for ease of reference…" and that the Reliability Coordination SDT (Project 2006-06) is writing the definition and will post that definition for vetting by the Industry. The SDT would note that Requirement R1 states that entities "shall comply" with identified Reliability Directives. Thus, by identifying the action as a Reliability Directive, the requirement is mandating the action. No change made.		
Midwest ISO Standards Collaborators	No	Requirement #1 Comments cannot be developed for this requirement until we are able to see a final draft of the definition of Reliability Directive. It will have a significant impact on this requirement. Requirement #9 SOL's have not been defined clearly enough to require an identified time limit for exceedance. These durations could be set by the Transmission Owners or Operators based on the type of equipment, not dictated in the standard. Requirement #10 It is not clear when the RC should be informed, before, during or after actions have been taken to correct an overload. This needs to be discussed. Depending on the urgency of the situation, it may not be appropriate for the TOP to inform the RC prior to taking actions. It should simply be a requirement for the TOP to log or record actions taken for future review. Requirement #13 It is not clear what TOP area needs to be monitored. Language needs to be added to clearly state that a TOP should have access to information on other TOP areas that could impact the local area.
Response: Requirement 1 - The SDT understands the perspective for the Requirement R1 comment, however, as pointed out in the Definition of Terms for TOP-		

Organization	Yes or No	Question 1 Comment
001-2, the "…definition (of Reliability Directive) is included here for ease of reference…" and the Reliability Coordination SDT (Project 2006-06) is writing the definition and will post that definition for vetting by the Industry. The SDT drafted the words such that the definition is secondary to the requirement. As written, the Transmission Operator would only "identify" an action as a Reliability Directive when the Transmission Operator "needs" an additional incentive to cut off discussion about whether or not the requested entity should carry out the action. If the entity carries out the action without the Transmission Operator identifying the action as a Reliability Directive, then the definition is not important. If the entity is not carrying out the requested action, then by identifying the requested action as a Reliability Directive, then the entity must comply – and again the definition is not critical to the requirement. Requirement R1 is designed to make clear that any request designated as a Reliability Directive must be carried out as stated (and repeated back). The definition only restricts the Transmission Operator in that the request must be necessary "to address an emergency." That allows the Transmission Operator to issue a Reliability Directive to respond to an Emergency and also during normal times, if needed, to preclude an Emergency condition from arising. Requirement 9 - The 30 minute limit is generally recognized as a time related to the risk of a second event occurring; thus 30 minutes is the maximum time. That does not preclude an operator from choosing a shorter duration (lesser restriction – e.g., higher MW) limit and using a shorter duration. No change made. Requirement 10 - The requirement does define an explicit time. It is the time after an action was taken ("…inform … of its actions…") and after the limit was exceeded ("…to return…when an IROL …has been exceeded…"). The communication therefore is not mandated prior to the action being taken. The fact that the communications are about "all of its actions" precludes communications "during" the action; thus leaving the communications to the post-action time period. No change made. Requirement 13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
Bonneville Power Administration	No	R5 - should refer to adjacent Transmission Operators. R8 - This daily documentation is burdensome. Reporting "all" SOL's to RC ahead of time as part of daily assessment in addition to the daily planned outage heads-up reporting. Suggest clarifying SOL as intended to be path loading limits and/or local area transmission service support limits, (the BES is a big system with lots of ratings, it can also mean voltage limits in addition to line and path limits). If there is a significant change to a limit, that would be important. R10 - Prefer having the RC call the TOP in 5 Minutes to ensure entity is aware of and acting on a limit excursion , rather than TOP interrupt system response to call RC to tell them the Operator is mitigating a SOL violation which is a already a NERC TOP standard to take immediate action. There's a typo in M12, M13, M14 when it refers to the wrong requirement due to renumbering R11 instead of R12, R12 vs. R13, and R13 vs. R14).
Response: Requirement 5 - The requirement limits the coordination to those Transmission Operators that the former Transmission Operator "knows" are impacted. If a Transmission Operator "knows" it will impact a non-adjacent Transmission Operator, then that fact should be communicated per this requirement. The requirement does not mandate direct communication – it can be handled through third party Transmission Operators – but it must be communicated. No		

Organization	Yes or No	Question 1 Comment
change made. Requirement 8 - The requirement does not specify “daily”. The reference to “significant change to a limit” must be defined by BPA before the SDT can address the comment further. No change made. Requirement 10 - The requirement does define an explicit time. It is the time after an act was taken (“…inform … of its actions…”) and after the limit was exceeded (“…to return…when an IROL …has been exceeded…”). The communication therefore is not mandated prior to the action being taken. The fact that the communications is about all of its actions precludes communications “during” the action; thus leaving the communications to the post action time period. No change made. The SDT did not see a need to be prescriptive about the reporting time. The proper phrase would be “as soon as time permits” but that phrase does not provide the clarity that compliance enforcers desire. No change made. The SDT corrected the typos in the Measures.		
SERC OC Standards Review Group	No	In R2, it appears that an entity might be faced with double jeopardy if it fails to notify the entity issuing the directive. Doesn’t R1 also include this same requirement? In R3, the phrase “affected of actual’ should be “affected by actual”. In R8 and M8, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”. In R12 and R13, it doesn’t seem possible to measure “monitoring”. These also seem like requirements that are ideally suited for the certification process. It appears that the numbering of the requirements within each measure may have gotten out of synch due to a cut and paste insert. In M8, SOLs should be singular. The data retention periods are too long and do not appear to serve the purpose of improving reliability. Specifically, the three (3) year retention period for SOL and IROL violations is two (2) years too long.
Response: Requirements 1 & 2 - Requirement R1 is written to address a priori prohibitions. This would be communicated at the time the actions were first being communicated. Requirement R2 is written to address conditions that arise after the entity agreed to do the action but found out later that conditions preclude such actions. No change made. Requirement 3 - Requirement was revised as requested. **R3.** Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. Requirement 8 - Local area reliability is not a defined term but rather (as stated in the requirement) it is “based on its (the Transmission Operator’s own)		

Organization	Yes or No	Question 1 Comment
assessment." The industry has debated this issue for a long time. This standard is written to ensure BES reliability by defining IROLs and to supporting individual Transmission Operators parochial definitions. The loss of a capital city in a state may have no impact at all on the BES, but politically that city is critical (think Washington, DC). Requirement R8 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). No change made. Requirements 12 & 13 – These requirements have been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. The SDT revised the Measures for the editorial errors as noted.. An entity need only keep the exception cases where actual violations have occurred, which should be a minimal amount of data. No change made.		
Southern Company Transmission	No	Southern's comments: Suggest modifying R3 language for additional clarity. Suggested alternatives might be "Each Transmission Operator shall inform its Reliability Coordinator of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis, and shall likewise inform any other Transmission Operators that are known or expected to be affected by those Emergencies" or "Each Transmission Operator shall inform its Reliability Coordinator and all other expectedly affected Transmission Operators of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis." In the first sentence of M5, the first usage of the word "operations" is redundant and can be struck. In R8, it is unclear what should be the treatment of SOLs that develop due to unanticipated system conditions that are not included in the Operation Planning analysis (i.e., real time system conditions deteriorate due to several unplanned outages). In R11, need to add "...within 30 minutes" after SOL. R14 can be mis-read to mean that the Transmission Operator grants approvals of outages, as opposed to granting the authority to grant approval to the System Operator. Also, it would be useful to clarify if the TOP still has the authority to also veto planned outages, in addition to the System Operator having that authority. M11 - M14 have references to incorrect Requirement numbers. In M8 and M14, the word "its" was incorrectly modified to "it's." SERC's comments: Southern participated in developing these comments and support them In R2, it appears that an entity might be faced with double jeopardy if it fails to notify the entity issuing the directive. Doesn't R1 also include this same requirement?

Organization	Yes or No	Question 1 Comment
		In R3, the phrase “affected of actual’ should be “affected by actual”. In R8 and M8, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”. In R12 and R13, it doesn’t seem possible to measure “monitoring”. These also seem like requirements that are ideally suited for the certification process. It appears that the numbering of the requirements within each measure may have gotten out of synch due to a cut and paste insert. In M8, SOLs should be singular. The data retention periods are too long and do not appear to serve the purpose of improving reliability. Specifically, the three (3) year retention period for SOL and IROL violations is two (2) years too long.

Response: Requirement R3 - In the case of Requirement R3, clarity of the text is difficult. First, the SDT offers what the words were meant to state: A Transmission Operator is mandated to contact its Reliability Coordinator about System conditions that either have caused the Transmission Operator to initiate Emergency procedures, or may cause the Transmission Operator to initiate Emergency procedures. Requirement R3 extends that contact to other Transmission Operators that either were identified in the Operational Planning Analysis (OPA) as being affected or the Transmission Operator knows is being affected. The wording is crafted to eliminate the possibility that an auditor would find the Transmission Operator non-compliant when another Transmission Operator not previously identified in any study or any procedure was affected. The words state that if you ‘know or expect’ impacts on someone than you must contact them to prepare them for the conditions, but if you don’t know or expect an entity to be affected, then the requirement does not apply.

Discussion of alternatives: The known or expected is a modifier to “other Transmission Operators.” The idea was that the Operating Plan would define the expected; the “known’ was to address the fact that a condition could arise that was not expected, but the Transmission Operator now ‘knows’ (from some other means) that another Transmission Operator (not known from the OPA) was affected. This phraseology was meant to capture that situation where a Transmission Operator finds out a fact that is not in its study. The requirement does not excuse the Transmission Operator just because the other Transmission Operator was not in the analysis – if you ‘know’ then you are required to contact them. On the other hand, if another Transmission Operator is impacted but your OPA did not identify that impact and you don’t have any knowledge of the impact, then Requirement R3 does not apply.

Given the above discussion, alternative 2 would not add clarity – since the “known or expected” modifies Emergency. No change made.

Measure M5 – The SDT agrees and has revised the measure accordingly.

> **M5**. Each Transmission Operator shall make available upon request, evidence that ~~operations~~ it ~~coordinated~~ informed other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas ~~with those Transmission Operators~~ in accordance with Requirement R5 unless conditions did not permit such ~~coordination~~ communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

Requirement R8 - Requirement R8 is a pre-event reporting requirement. This requirement is strictly focused on what to do with the SOLs that are pre-assigned.

Organization	Yes or No	Question 1 Comment
The requirement says if a Transmission Operator wants to address an SOL on the same level as an IROL, then it must inform the Reliability Coordinator of which SOLs are to be raised to that level. Thus, exceedances of SOLs that arise and were not identified in the Operational Planning Analysis will not be covered in Requirement R8. No change made. Requirement R11 – The SDT agrees and has added “within 30 minutes” **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL’s T_v, or of an SOL identified in Requirement R8 within 30 minutes. Requirement R14 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. The SDT corrected typos including Measure 8. **M8**. Each Transmission Operator shall make available evidence that it has informed it~~'~~s Reliability Coordinator of each SOL~~s~~ which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. For SERC comments, see SERC response.		
FirstEnergy	No	We agree with many of the changes the drafting team made to this standard. However, we have the following comments and suggestions: a. With respect to R7 and R11 in relationship to IROLs, R11 is inherent in R7. If an entity is not permitted to operate outside an IROL limit for longer than its Tv, then it needs to implement whatever actions are required to comply with Tv including directing "others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv." R9 and R11 have the same issue with respect to SOL's. M3 is silent on evidence related to the Operational Planning Analysis. Did the drafting team intend for this data to be available for inspection as a means of proving or disproving the affect on a Neighboring Transmission Operator and thereby the need to contact them? If it is the intent of the drafting team to use the Operational Planning Analysis as evidence, then it should be specifically stated in M3. If it is the intent of the drafting team for an entity to be able to prove "conditions did not permit such coordination" then that evidence should be specified in the measures. b. R11 - We believe that requiring the TOP to mitigate IROLs is outside their scope per the functional model. The RC holds the authority over the tools needed to mitigate an IROL and is the appropriate entity responsible for this requirement. Also, it seems as though this requirement is duplicative of IRO-009-1 R4 which states "When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to

Organization	Yes or No	Question 1 Comment
		mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. (Violation Risk Factor: High) (Time Horizon: Real-time Operations)". c. R13 - We suggest the team remove the phrase "within any Transmission Operator Area" from the requirement. We believe this phrase is not necessary and adds confusion. d. R14 - The original SAR charged with addressing Order 693 directive 1660 required the standards to identify the minimum monitoring and analysis capabilities. The new requirement R14 does not fully address these minimum capabilities and will leave the requirement ambiguous from a compliance and enforcement standpoint. We suggest the team fully address the directive and clarify the requirement. e. Measures M10 through M14 make reference to the wrong requirements.
Response: a. The industry has agreed that violations of IROLs must never occur – hence Requirement R7. Requirement R7 is meant as a flat-out prohibition on violating IROLs – the concept being that IROL violations will/may take down the BES. The industry also seems supportive of extending the IROL violation to some (some would even like to extend the prohibition to all) SOLs which the Transmission Operator decides are important at the local level, hence Requirement R9. Requirement R11 is an action requirement that mandates not just avoiding a violation (Requirements R7 & R9) but to reduce any and all exceedances. The SDT interpreted the industry as wanting to prohibit the Transmission Operator not just to stay within the MW and time margins, but also wanted the Transmission Operators to act when any magnitude limit is exceeded no matter how short a time. Requirement R11 mandates that once the magnitude is exceeded, the Transmission Operator must be taking action. Requirements R7 and R9 force the Transmission Operators to be concerned with any and all System conditions that "can" lead to going over the magnitude and duration limit. While not mandating a multiple Contingency standard, these two requirements force Transmission Operators to be sensitive to (i.e., not ignore) conditions that may result in common mode failures that would not occur during normal conditions. No change made. Measure M3 – The requirement is to 'inform' and the SDT believes that the measure correctly states what evidence is needed to prove that an entity 'informed'. No change made. b. The SDT believes that there are situations where the Transmission Operator must take actions or direct others to act over and above those situations where the Reliability Coordinator does same. No change made. c. This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. d. This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. e. The SDT has corrected the typos.		
Dominion	No	Agree with changes to most requirements and measures, but with exceptions as noted below: R2 - Is covered in R1. Do not agree with entity being subject to non-compliance for same shortcoming under 2 requirements. We suggest R2 be removed or that R1 and R2 be revised so that the requirement to inform the TOP not be included in both. R13 - Is the sentence meant imply that a TOP should monitor or have access to information/facilities in

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>another TOP Area that could impact its TOP Area? If so, we believe the current draft language should be revised to improve clarity of intent. We suggest revising to read “Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within external Transmission Operator Area(s) as necessary to perform such analysis”

M1/M2 - revise measures so that entity is not subject to non-compliance for failure to notify TOP twice, pursuant to changes in R1/R2.

M8 - change SOLs to SOL.

M13 - revise pursuant to R13.</td></tr>
<tr><td colspan="3">Response: <u>Requirements R1 & R2 (and Measures M1 & M2) - </u>Requirement R1 is written to address a priori prohibitions. These would be communicated at the time the actions were first being communicated. Requirement R2 is written to address conditions that arise after the entity agreed to do the action but found out later that conditions preclude such actions. No change made.

<u>Requirement R13</u> – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

<u>M8</u> – The SDT made the indicated revision.

M8. Each Transmission Operator shall make available evidence that it has informed it<s>'</s>s Reliability Coordinator of each SOL<s>s</s> which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.</td></tr>
<tr><td>Terry Harbour</td><td>No</td><td>The proposed TOP-001-2 standard is a significant improvement, but there are still important items that need to be addressed including: Comments cannot be developed for this requirement until a final draft of the definition of Reliability Directive is presented as it will have a significant impact on TOP-001-2 and R1. When Reliability directive is defined, the definition of a Reliability Directive is too broad and should be limited to “Abnormal conditions that require operational actions to avoid instability, uncontrolled separation and cascading as defined in Section 215 of the Federal Power Act.”

TOP-001-2-R9: SOL’s should not be part of the TOP-001-2 standard as there are not identified timeframes in the NERC standards today. However, if SOL’s must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded such as 30 minutes after exceeding the specified SOL limit. An example definition might be non-thermal SOL’s are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability. Many times scheduled transmission outages coupled with weather (drought, wind front, heat wave, etc) and strong market moves can drive unexpected SOL exceedances where units and markets cannot move within</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		30 minutes to redispatch sufficient generation. Coupling SOLs with time frames and penalties will drive unforeseen market impacts. TOP-001-2-R10: It isn't clear when the RC should be informed, before, during, or after actions have been taken to correct an overload. Depending upon the urgency of the situation, it might not be important to notify the RC, therefore the requirement should be changed to the TOP should record actions taken for future review. For TOP-001-2-R6 replace "coordinate" with "notify the RC and negatively impacted adjacent interconnected NERC registered entities of " For TOP-001-2-R3, the words "and anticipated" needs to be dropped as an unmeasurable requirement. In TOP-001-2-R2 and R4, "expected to be affected" would include known. We asked the SDT to please strike known. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? The measures for TOP-001-2-R5 and R8 need to be clear that these are event driven requirements and evidence is only required if an "event" has occurred. In R6, the word "telemetering" should be capitalized as it is a defined term in the NERC Glossary. The terms "control equipment" and "associated communications channels" are not defined in the glossary at all. Recommend modifying the wording to ensure consistency between standards. R14 uses the term "monitoring and analysis capabilities". This term is not defined in the NERC Glossary. R13 implies that a TO's Operational Planning Analyses should be monitoring facilities external to its own operating area when they have no control or responsibility for said facilities. It is not a TO's responsibility to monitor regional system conditions; therefore this requirement should be removed. FERC Order 693, paragraphs 1660 and 1661 do not specifically mention any of the verbiage in requirements R12, R13, & R14; therefore the preceding statement should be considered.
Response: "Reliability Directive" is not meant to equate to urgency of a situation; rather it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the		

Organization	Yes or No	Question 1 Comment
phraseology would raise the text to the same level as an act to relieve the condition itself. No change made. Requirement R9 - The 30 minute limit is generally recognized as a time related to the risk of a second event occurring, thus 30 minutes is the maximum time. That does not preclude an operator from choosing a shorter duration (lesser restriction – e.g., higher MW) limit and using a shorter duration. No change made. Requirement R10 - The requirement does define an explicit time. It is the time after an act was taken ("…inform … of its actions…") and after the limit was exceeded ("…to return…when an IROL …has been exceeded…" The communication therefore is not mandated prior to the action being taken. The fact that the communication is about all of its actions precludes communication "during" the action; thus leaving the communications to the post-action time period. The SDT did not see a need to be prescriptive about the reporting time. The proper phrase would be "as soon as time permits," but that phrase does not provide the clarity that compliance enforcer's desire. No change made. Requirement R6 – The SDT agrees and has revised the wording accordingly. **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities. Requirement R3 - From a compliance auditor's perspective, the auditor is constrained to depend on the Transmission Operator on whether or not an Emergency is "anticipated". The rationale for the language was to put the Transmission Operator on alert that even the expectation of an Emergency is enough to trigger communications. Requirement R2 & R4 - Without the phrase "expected to be affected," the requirement would only apply in the case of actual Emergencies (which may be too late to make use of all available options). A real Emergency that is known to impact Transmission Operator X may not necessarily have been shown by the OPA to affect Transmission Operator X. This requirement is written in a way that it does not excuse a Transmission Operator that runs an OPA that has no problems, from its obligation to contact others that it knows are de facto affected. No change made. Requirement R7 - The issue of percentages was discussed and was evaluated not to be strong enough for this situation. One violation is unacceptable. More than 4 violations of a requirement that addresses BES so directly cannot be mitigated by percentages. No matter how big or how small a Transmission Operator is, non-compliance with this requirement cannot be justified. No change made. Requirements R5 & 8 – The SDT believes that the wording is correct as stated. No change made. Requirement R6 – The SDT has changed the wording for clarity. Requirement R14 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirement R13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirements R12 & R13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		

Organization	Yes or No	Question 1 Comment
MRO's NERC Standards Review Subcommittee	No	The proposed TOP-001-2 standard is a significant improvement, but there are still important items that need to be addressed including: Comments cannot be developed for this requirement until a final draft of the definition of Reliability Directive is presented as it will have a significant impact on TOP-001-2 and R1. When Reliability directive is defined, the definition of a Reliability Directive is too broad and should be limited to “Abnormal conditions that require operational actions to avoid instability, uncontrolled separation and cascading as defined in Section 215 of the Federal Power Act.” TOP-001-2-R9: SOL’s should not be part of the TOP-001-2 standard as there are not identified timeframes in the NERC standards today. However, if SOL’s must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded such as 30 minutes after exceeding the specified SOL limit. An example definition might be non-thermal SOL’s are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability. TOP-001-2-R10: It isn’t clear when the RC should be informed, before, during, or after actions have been taken to correct an overload. Depending upon the urgency of the situation, it might not be important to notify the RC, therefore the requirement should be changed to the TOP should record actions taken for future review. For TOP-001-2-R6 replace “coordinate” with “notify the RC and negatively impacted adjacent interconnected NERC registered entities of” For TOP-001-2-R3, the words “and anticipated” needs to be dropped as an unmeasurable requirement. In TOP-001-2-R2 and R4, “expected to be affected” would include known. We asked the SDT to please strike known. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? The measures for TOP-001-2-R5 and R8 need to be clear that these are event driven requirements and evidence is only required if an “event” has occurred. In R6, the word “telemetering” should be capitalized as it is a defined term in the NERC Glossary. The terms “control equipment” and “associated communications channels” are not defined in the glossary at all. Recommend modifying the wording to ensure consistency between standards. R14 uses the term “monitoring and analysis capabilities”. This term is not defined in the NERC Glossary. R13 implies that a TO’s Operational Planning Analyses should be monitoring facilities external to its own operating area when they have no control or responsibility for said facilities. It is not a TO’s responsibility to

Organization	Yes or No	Question 1 Comment
		monitor regional system conditions; therefore this requirement should be removed. FERC Order 693, paragraphs 1660 and 1661 do not specifically mention any of the verbiage in requirements R12, R13, & R14; therefore the preceding statement should be considered.

Response: "Reliability Directive" is not meant to equate to urgency of a situation; rather it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made.

Requirement R9 - The 30 minute limit is generally recognized as a time related to the risk of a second event occurring, thus 30 minutes is the maximum time. That does not preclude an operator from choosing a shorter duration (lesser restriction – e.g., higher MW) limit and using a shorter duration. No change made.

Requirement R10 - The requirement does define an explicit time. It is the time after an act was taken ("…inform … of its actions…") and after the limit was exceeded ("…to return…when an IROL …has been exceeded…" The communication therefore is not mandated prior to the action being taken. The fact that the communication is about all of its actions precludes communication "during" the action; thus leaving the communications to the post-action time period. The SDT did not see a need to be prescriptive about the reporting time. The proper phrase would be "as soon as time permits," but that phrase does not provide the clarity that compliance enforcer's desire. No change made.

Requirement R6 – The SDT agrees and has revised the wording accordingly.

> **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

Requirement R3 - From a compliance auditor's perspective, the auditor is constrained to depend on the Transmission Operator on whether or not an Emergency is "anticipated". The rationale for the language was to put the Transmission Operator on alert that even the expectation of an Emergency is enough to trigger communications.

Requirement R2 & R4 - Without the phrase "expected to be affected," the requirement would only apply in the case of actual Emergencies (which may be too late to make use of all available options). A real Emergency that is known to impact Transmission Operator X may not necessarily have been shown by the OPA to affect Transmission Operator X. This requirement is written in a way that it does not excuse a Transmission Operator that runs an OPA that has no problems, from its obligation to contact others that it knows are de facto affected. No change made.

Requirement R7 VSLs - The issue of percentages was discussed and was evaluated not to be strong enough for this situation. One violation is unacceptable. More than 4 violations of a requirement that addresses BES so directly cannot be mitigated by percentages. No matter how big or how small a Transmission Operator is, non-compliance with this requirement cannot be justified. No change made.

Requirements R5 & 8 – The SDT believes that the wording is correct as stated. No change made.

Organization	Yes or No	Question 1 Comment
Requirement R6 – The SDT has changed the wording for clarity. Requirement R14 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirement R13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirements R12 & R13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
PJM	No	There are several issues with Requirement 6: o The requirement assigns responsibility to 3 entities for one task. NERC standards are designed to clearly assign responsibility to provide a clear measurement and allocation of non-compliance. R 6 as worded requires “coordination” between and among each entity. • Coordination is not defined. Does coordination mean “informing” another party? Does it mean “directing a new solution”? Does it mean “asking permission” of a third party? Who is non-compliant when two (or more) parties do not agree with a proposed solution? How many alternatives proposals must be considered? Suggest the requirement be rewritten as a series of independent requirements with sub-bullets to identify specific tasks. Example: Each TOP shall inform all affected reliability entities of planned outages of active real-time communications channels: o Interpersonal channels • Data exchange channels for any BES elements or elements involved in identified IROL computations • Asset direct-control devices (reactive control equipment,...) Each TOP shall inform all affected parties of alternative means to be used for the duration of the proposed outage. Each BA shall inform all affected reliability entities of planned outages of active real-time communications channels: o Interpersonal channels o Data exchange channels for any BES elements or elements involved in identified IROL computations o Asset direct-control devices (regulation control signals; resource dispatch equipment,...)Each GOP shall inform all affected reliability entities of planned outages of active real-time communications channels: o Interpersonal channels o Data exchange channels for any BES elements or elements involved in identified IROL computations o Asset direct-control devices Each reliability entity inform by the TOP in Rx.x, (or by the BA in Ry.y or by the

Organization	Yes or No	Question 1 Comment
		GOP in Rz.z) shall acknowledge the receipt of the information provided in Rx.x (or in Ry.y or Rz.z) to the respective TOP (BA or GOP). Requirement #13Delete the phrase "...within ANY Transmission Operator Area". The phrase has the potential to add confusion rather than clarity to the requirement.
Response: Requirement R6 – The SDT has modified the requirement to address your concern. **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities. Requirement R13 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
IRC Standards Review Committee	No	Requirement #1 Comments cannot be developed for this requirement until we are able to see a final draft of the definition of Reliability Directive. It will have a significant impact on this requirement. Requirement #9 A 30-minute time limit has been identified in Requirement 9, but that may be an inappropriate time based upon the variability that exists with actual system operating limits. In the case of thermal limits, some may be 15 minutes others may be 4 hours for different facilities. The same facility may have a 4 hour loading limit, and a 2 hour limit at a higher magnitude, as well as, perhaps, a 30 minute limit at a higher magnitude yet. If the limits were allowed to only be set at 30 minutes, how are longer limits incorporated? Of course it is imprudent to operate a facility at the magnitude corresponding to a four hour limit for greater than four hours. But how is that limit identified and communicated if the System Operating Limit must be mitigated within 30 minutes? Any such operating parameter will be recognized as an SOL, then requiring a 30 minute limit if Requirement 9 is left as is. Requirement 8 mandates that limits be set to support local area reliability. Operating a facility for five hours at its four hour limit is contrary to that requirement. Transmission Operators need SOLs to be described and communicated in terms of both magnitude and associated time, but that time need not be limited to 30 minutes. The duration and magnitude of the SOL should be set by the Transmission Owners or Operators based upon respecting the facility and equipment ratings as required by the FAC standards. Requirement 9 would better serve reliability to require SOLs (which are identified in Requirement 8) to be described in specific terms of both magnitude and associated time. If needed, a fallback position could be maintained that establishes 30 minutes as the default time limit if no other limit is specifically defined in the SOL.

Organization	Yes or No	Question 1 Comment
		Requirement #13 It is not clear what TOP area needs to be monitored. Language needs to be added to clearly state that a TOP should have access to information on other TOP areas that could impact his local area.
Response: **“**Reliability Directive” is not meant to equate to urgency of a situation; rather, it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator’s request or is debating the request can be “made to” to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made. Requirements R8 & 9 - The issue posed by the IRC seems to be more academic than real. Requirement R8 does not mandate that any SOL be defined. Requirement R8 only requires that a Transmission Operator tell its Reliability Coordinator of those SOLs that the Transmission Operator has decided it wants the Reliability Coordinator to treat in the same fashion as the Reliability Coordinator would treat IROLs. IRC is using its definition for SOL not the Requirement R8 definition. Requirement R8 defines SOL as a limit that the Transmission Operator itself has designated for monitoring and control by the Reliability Coordinator. Every operating limit does not automatically come under that requirement. However, if a Transmission Operator wants every operating limit to be addressed by the Reliability Coordinator in the same way that the Reliability Coordinator addresses IROLs, then that is allowed under this requirement. If the Transmission Operator wants none of its operating limits handled like an IROL, that too is allowed under the requirement. The Transmission Operator requirements protect the BES under the IROL requirements; these non-IROL limits are optional. NERC has used a 30-minute time frame for several Contingency-related standards based on a review that showed the risk of a second Contingency is greatly increased after 30 minutes. While a 4-hour rating may be used, if a single Contingency were to occur, there would be no problem, but a second Contingency would be a problem. While the requirement does not mandate reserves for multiple Contingencies, the requirement does impose a time frame of 30 minutes. There is no one SOL for a Facility. Each Facility has an infinite number of magnitude vs. duration curves. No change made. Requirement R13 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	No	R1 - ERCOT ISO does not agree with the addition of the word ‘identified’ because it implies each Reliability Directive needs to be preceded with an additional statement like “the following is a Reliability Directive”. In a true emergency, clear concise communication and an understanding of what action is required to mitigate the situation is necessary. The addition of another sentence before each required action delays communication. ERCOT ISO thinks a Reliability Directive should not have to be declared as such, prior to issuance. Compliance should not be measured by whether the System Operator remembered to state “this is a Reliability Directive”, but should be measured by whether the Reliability Directive was properly issued and three-part communication was utilized. NOTE: Requirements 1 and 2 are dependent upon the approval of the term Reliability Directive, which is being proposed by Project 2006-06 Reliability Coordination.

Organization	Yes or No	Question 1 Comment
		R2 - Add Operations Planning to the Time Horizon because R1 includes Operations Planning in the Time Horizon. R1 and R2 occur in the same Time Horizons, since R1 requires an entity to comply to a Reliability Directive issued by a TOP and R2 requires an entity who cannot comply to notify the issuing TOP.NOTE: Requirements 1 and 2 are dependent upon the approval of the term Reliability Directive, which is being proposed by Project 2006-06 Reliability Coordination. R9 VSL - The TOP, when notifying the RC, should identify the appropriate Tv. The associated VSL should be high and not severe and should only be severe when multiple instances occur.
Response: **Re**liability Directive is not meant to equate to urgency of a situation; rather, it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. Communications between registered entities occur almost continuously. Within those communications are instructions from Reliability Coordinators and Transmission Operators. Those instructions are expected to be followed at all times. However, there are times when people question instructions. At those times, the recipient of an instruction that is identified as a Reliability Directive needs a clear understanding that it is a Reliability Directive. The requirement is consistent with the ERCOT position that added words should not be mandated; the difference is that the ERCOT proposal would mandate the repeating of actions, whereas the requirement does not. No change made.. Requirement R2 – The SDT has added the time horizon as requested. **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]* Requirement R9 – If a VSL is binary, and the SDT believes that this VSL should be binary, it must be Severe. No change made.		
Joylyn Faust	No	R2 is ambiguous, must a BA inform it's TO of an inability to perform a directive after the directive has been issued or at anytime its systems are down and it has temporarily lost its ability to perform some function. R12-14 appear to provide the TO with omnipotent information rights which may include the ability to create monitoring requirements of other entities and control over maintenance schedules of other entities telemetry and associated facilities. Furthermore reciprocal data rights are not provided.
Response: Requirement 2 - R2 is an after-the-request requirement. If, after being given a Reliability Directive, the entity finds out that its equipment cannot perform as expected, Requirement R2 mandates the entity tell the Reliability Coordinator so that the Reliability Coordinator may make other arrangements. If the		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">system were down, then other NERC requirements mandate that such conditions be communicated. This requirement is just designed for states when the entity expects to be able to do something but finds out that it cannot. No change made.

<u>Requirements 12-13 -</u> These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.</td></tr>
<tr><td>Jonathan Appelbaum</td><td>No</td><td>“Operational Planning Analysis” is not a defined term in the NERC Glossary and a proposed definition is not included in the Draft Standard. TOP-001 and TOP-002 have capitalized the term indicating a definition. TOP-002 information box says “by definition Operational Planning Analysis includes Contingency Analysis.”

TOP-001 R12 and R13 were added in this posting to address Order 693 paragraph 1660 and 1661 direction to include the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System. The drafting team utilizes the phrase “shall monitor, or shall have access to information about, conditions and Facilities...” By offering an alternative to “monitor” the drafting team is implying there is a difference between “monitor” and “having access to information”. UI suggests retaining “monitor” and removing “access to information about” because the TOP needs the minimum capability of monitoring the Facilities in its area to perform its reliability functions.</td></tr>
<tr><td colspan="3">Response: Operational Planning Analysis is in the Glossary. No change made.

Requirements 12 and 13 have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.</td></tr>
<tr><td>Jon Kapitz</td><td>No</td><td>R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. Xcel Energy has concerns about the use of the term “affected”. This can be widely interpreted by the entity and compliance enforcement authority. We suggest that language limit the entity’s obligation to Adjacent entities and the Reliability Coordinator. The RC should be held responsible for making this assessment from a regional perspective and make notifications to other entities as it is required to or deems necessary.

R13. Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. Xcel Energy has concerns as to whether this requirement indicates that a TOP must have monitoring capability for other TOP areas. This requirement should encompass only a TOP’s own area.

R14. Each Transmission Operator shall provide approval rights for planned maintenance of its monitoring and analysis capabilities to its System Operators. Xcel Energy believes this requirement should be worded so that it covers only monitoring capabilities for its own area, and items that it is in control of. (e.g. not feeds from other entities that input into a TOPs own monitoring capability)</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		M11 through M14 list incorrect associated requirements. This appears to be a mapping issue.
Response: Requirement 3 - The SDT respects the sensitivity of regarding the term “affected.” The SDT perspective was to avoid the possibility that any and every ‘affect’ in Real-time would come under this requirement, and inserted the phrase “… expects to be affected…” This would mean that if the Transmission Operator “expected” to affect another entity, then Requirement R3 would require the Transmission Operator to communicate that expectation. However, if the Transmission Operator did not expect to impact a third-party, then there would be no obligation. As written, the requirement provides a common sense approach. To be found non-compliant, an auditor would have to show evidence that the Transmission Operator knew that there would be an impact and knowingly did not inform the impacted entity. This would require an auditor to peruse data and make a case. It is possible to show non-compliance, but it will be the auditor’s responsibility to prove that fact, as opposed to the Transmission Operator being subject to proving that. While the Reliability Coordinator is responsible for ensuring that every entity knows its role, this requirement recognizes that the Transmission Operator can have a role in analyses and information that may not be analyzed in the detail that the Transmission Operator can provide. No change made. Requirement 13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirement R14 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. The SDT has corrected the typos in the measures.		
Howard Rulf	No	R7: What does it mean to be “outside” an IROL? Vague. R8: Since any SOL is to “ensure operation within acceptable reliability criteria” this requirement requires that the TOP inform the RC of all SOLs. How can the Time Horizon be Real-Time Operations? Operational Planning Analysis is done at least day ahead? R9: What does it mean to be “outside” an SOL? Vague. R10: How do I correlate “within limits” to “inside/outside”?
Response: Requirements 7, 9, & 10 - The term “outside” was used to recognize that there are both upper and lower limits. No change made. Requirement 8 – Requirement R8 is an a priori requirement. All it is meant to say is “if a Transmission Operator wants its Reliability Coordinator to observe a given non-IROL limit in the same way as the Reliability Directive observes IROLs, then the Transmission Operator must tell that Reliability Coordinator which limits are in that category. This must be done ahead of time. It can be done in the OPA or in the Long-term planning horizon or any other advanced time – it cannot be done in Real-time (where Real-time is defined as ‘this instant’) or after-the-fact. No change made.		
RoLynda Shumpert	No	In R3 the language should be "...be affected by actual..." and not "...be affected of actual..." Measures M10-M14 are off by 1 in pointing back to their respective requirements (i.e. M10 is pointing back to

<table>
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<tr><td></td><td></td><td>R9, etc).

It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.</td></tr>
<tr><td colspan="3">Response: Requirement 3 – The SDT has revised Requirement R3 to address your comment and those of others.

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

The SDT has corrected the typos.</td></tr>
<tr><td>Greg Rowland</td><td>No</td><td>What does the drafting team mean by “its inability” in R2 to perform a Reliability Directive? There clearly needs to be a distinct difference between the reasons in R1 and “inability” in R2. Duke wants to eliminate the possibility of double jeopardy for an entity to be assessed a possible violation for non-compliance to one action with it stated similarly in two requirements.

R3 typo - change the word “of” to “by”.

R8 - the phrase “supporting its local area reliability” is unclear. Replace it with the phrase “having an Adverse Reliability Impact”. This adds clarity and also recognizes that local area problems that don’t rise to the level of Adverse Reliability Impact should not be treated as SOLs required to be reported to the RC under this standard.

R9 - insert the phrase “as having an Adverse Reliability Impact” after the phrase “Requirement R8”, making R9 consistent with R8.

R13 - strike the phrase “shall monitor, or”. The TOP doesn’t need to directly monitor facilities in other TOP areas.

M1 - strike the word “either” and replace the phrase “or, (b) informed the Transmission Operator that” with the word “unless”. This makes M1 consistent with the R1 revision above.

M3 typo - replace the word “of” with the word “by”.

M5 typo - the word “operations” appears twice. Need to strike the first one.

M8 - replace the phrase “supporting its local area reliability” with the phrase “having an Adverse Reliability Impact”, consistent with the R8 revision above.

M13 - strike the phrase “can monitor, or” consistent with the R13 revision above.

R1 VSL - replace the phrase “and the respective entity did not inform the Transmission Operator that such</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		action would" with the phrase "and compliance with the Reliability Directive would not", consistent with the R1 revision above. VSLs for R3, R5, R6 and R8 - The mixing of numbers with percentages and the phrase "whichever is less" in these VSLs is confusing. For example, if under R5 there are four affected entities, and the TOP does not coordinate operations with one of the four, then that is one entity, or 25% of the total. What does "whichever is less" mean? Is that a Lower or Severe violation? Conversely, if there is only one affected entity and the TOP does not coordinate operations with that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation? R8 VSLs - In each VSL, replace the phrase "supporting its local area reliability" with the phrase "having an Adverse Reliability Impact, consistent with the R8 revision above. R13 VSL - Strike the phrase "monitor, or", consistent with the R13 revision above.

Response: Requirements 1 & 2 - Requirement R1 is written to address a priori prohibitions. These would be communicated at the time the actions were first being communicated. Requirement R2 is written to address conditions that arise after the entity agreed to do the action, but found out later that conditions preclude such actions. No change made.

Requirement 3 – The SDT revised the requirement to address your comment.

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

Requirement 8 - Local area reliability is not a defined term but rather (as stated in the requirement) it is "based on its (the Transmission Operator's own) assessment." The industry has debated this issue for a long time. This standard is written to ensure BES reliability by defining IROLs and by supporting individual Transmission Operators parochial definitions. The loss of a capital city in a state may have no impact at all on the BES, but publicly that city is critical (think Washington, DC). Requirement R8 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). Given that the requirement is for local concerns that could mean that the limit is not necessary for local reliability but rather "supports" local reliability. No change made.

Requirement 9 - An SOL that has adverse reliability impacts is, by definition, an IROL. Requirement R8 says that if it isn't an IROL and you want the limit to be controlled in the same way as an IROL, then tell the Reliability Coordinator which limits you want. [Note what all this means –when running its planning and or operating analysis, the Reliability Coordinator does not find the said limit as causing any BES problems – thus the Reliability Coordinator is not concerned with the said limit. The Transmission Operator however, wants, or is required by some other authority, to treat the said limit as if that limit had BES implications. Such information must be conveyed by the Transmission Operator to the Reliability Coordinator.] Thus, inserting the proposed text will not accomplish the intent of the requirement. No change made.

Requirement 13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis

Organization	Yes or No	Question 1 Comment
Capabilities. The SDT reviewed the typos and made the changes where deemed appropriate. The mixing of numbers and percentages is standard for VSLs. It is designed to allow for size differences in applicable functional entities. 'Whichever is less' means simply that you use the option that is less numerically. No change made.		
Michael Lombardi	No	Both Requirements R12 and R13 are considered vague and open to interpretation. For example, what type of information is to be monitored and what is meant by conditions? Language needs to be added to clearly state what a TOP needs to accomplish pursuant with these requirements. Various Measures appear to have incorrect Requirement references. For example, the text of Measure M14 refers to Requirement R13. Please verify / correct the Requirement references for all Measures. The term "Operational Planning Analysis", is capitalized to identify it as a defined term yet the NERC Glossary of Terms (updated 4/20/2010) indicates that the term has not been FERC approved. NU is concerned that the terms Operational Planning and Operational Planning Analysis are not FERC approved and may not be consistently applied throughout the industry. Suggest these terms be reviewed as part of this standard to ensure industry consensus on these terms and subsequently seek FERC approval, as required.
Response: Requirements 12-13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. The SDT has corrected the typos. Operational Planning Analysis is contained in the NERC Glossary. Once it is approved by the BOT, the SDT is required to use the term. No change made.		
Richard Kafka	No	R6 requires coordination which leads to questions regarding who is non-compliant. It would be more proper to require reporting and approval requirements. RCs already are required to coordinate with each other. R9 sets a 30 minute limit on all identified SOLs (as opposed to allowing different times). This would require all facilities to have the same time limits for ratings. That should be addressed in FAC-008.
Response: The SDT has revised Requirement R6 to address your concerns. **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities. NERC has used a 30-minute time frame for several Contingency-related standards based on a review that showed the risk of a second Contingency is greatly increased after 30 minutes. While a 4-hour rating may be being used, if a single Contingency were to occur, there would be no problem, but a second		

Organization	Yes or No	Question 1 Comment
Contingency would be a problem. While the requirement does not mandate reserves for multiple Contingencies, the requirement does impose a time frame of 30 minutes. There is no one SOL for a Facility. Each Facility has an infinite number of magnitudes vs. duration curves. No change made.		
Saurabh Saksena	No	R13 states that - Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. What does “Facilities” in R13 refer to? Is it any facilities that are included in the analysis or those that have the potential to cause violations? Suggest replacing “...Facilities identified in its Operational Planning Analysis” by text in R8 - “...identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis.” TOP-001 R13 also says "...within any Transmission Operator Area...” Does the drafting team mean within that particular TOP's area? It would be clearer if it said "...within its area...” If they really do mean another TOP's area, that is unrealistic. It could imply that we need to have info for TOP in Florida. TOP-001 R8 & TOP-002 R2 - When referencing SOLs both say something like "SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability...” National Grid suggests deleting “...which, while not IROLs...”
Response: <u>Requirement 13</u> – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. <u>Requirement 8 -</u> The wording “while not IROLs” was inserted to make clear that not all limits have adverse reliability impacts, but that some limits that do not have reliability impacts can still be held to a higher standard of operations - as long as those limits are identified. An SOL that has adverse reliability impacts is by definition an IROL. Requirement R8 says that if it isn’t an IROL and you want the limit to be controlled in the same way as an IROL, then tell the Reliability Coordinator which limits you want. [Note what all this means –when running its planning and/or operating analysis, the Reliability Coordinator does not find the said limit as causing any BES problems – thus the Reliability Coordinator is not concerned with the said limit. The Transmission Operator however, wants, or is required by some other authority, to treat the said limit as if that limit had BES implications. Such information must be conveyed by the Transmission Operator to the Reliability Coordinator.] Thus, inserting the proposed text will not accomplish the intent of the requirement. No change made.		
Catherine Koch	No	R1 - The addition of the term “identified” does not completely answer the question of who needs to identify the communication as a Reliability Directive. Simply adding the term means that it might be interpreted to mean that that the entity receiving a communication from a Transmission Operator might need to identify the communication as a Reliability Directive from its content and context. The following formulation is more clear: “Each Balancing Authority ... shall comply with each Reliability Directive that its Transmission Operator issues and identifies as a Reliability Directive ...” Given the importance of these requirements, clarity must not be sacrificed for brevity. R8 - The use of the phrase “have been identified” is unnecessary in this requirement. The Transmission

Organization	Yes or No	Question 1 Comment
		Operator has an independent obligation to identify these SOLs under the FAC standards. In addition, the phrase “its local area reliability” is ambiguous. If the intent of this term is to address a certain set of SOLs that have more than a purely local effect, then the phrase should be modified to something like “regional reliability” or “that may affect its neighboring Transmission Operator Areas”. The requirement should read “Each Transmission Operator shall inform its Reliability Coordinator of all SOLs that, while not IROLs, support regional reliability based on its assessment of its Operational Planning Analysis” or “Each Transmission Operator shall inform its Reliability Coordinator of all SOLs that, while not IROLs, that may affect its neighboring Transmission Operator Areas based on its assessment of its Operational Planning Analysis.” M1 - To be consistent with the recommended revisions to R1, the measurement should be revised to read “Each Balancing Authority ... (a) complied with each Reliability Directive that its Transmission Operator issued and identified as a Reliability Directive, ...". Additionally we suggest that the measures provide guidance of how to prove a Reliability Directive was not issued in order to be complete in demonstrating compliance with the requirement. This same suggestion rings through all the measures.M2 - This measurement duplicates a portion of M1.
Response: Requirement 1 & Measure M1– The SDT does not agree that the suggested change adds any clarity. No change made. Requirement 8 - Technically you are correct that the phrase is not needed. However, in this transitional period when a term is being parsed in a special way, the added words are seen (in this case) to be helpful. The words were crafted to mean “local issues.” An outage affecting the White House would not be an impact on the BES but “locally” it would be unacceptable; thus a limit that impacted the White House would be identified by the DC Transmission Operator to the Reliability Coordinator as a special case SOL that must be respected in the same way an IROL is handled. Thus Requirement R8 does mean local and does not refer to impact on others. Note inter-area impacts would be more likely identified by the Reliability Coordinator than the Transmission Operator since the Reliability Coordinator has more intelligence on surrounding areas. No change made.		
Jason Shaver	No	Requirements #1 & 2 ATC supports Requirements 1 and 2 if the definition of Reliability Directive, as provided in TOP-001-2, is not modified. Any change to the proposed definition of Reliability Directive will require us to reevaluate our position. Requirement #3 Issue 1: ATC is concerned with the wording of Requirement 3 because it blends real time Emergencies situations with issues or concerns that are identified in Operational Planning Analysis for next day, week, month or year. Definitions: “Emergency” and “Operational Planning Analysis”: Emergency: “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 BES” Operational Planning Analysis: “An analysis of the expected system condition for the next day’s

Organization	Yes or No	Question 1 Comment
		operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generation outages, equipment limitations, etc.).” If an Emergency by definition requires automatic or immediate manual action then there would be few if ever a situation in which a next day study would require either automatic or immediate manual action. What reliability objective is the SDT attempting to achieve when combining these two distinct situations into one requirement? Because of this observation ATC believes that the language about anticipated Emergency and Operational Planning Analysis should be deleted. If the SDT does not believe that these deletions are necessary then we request that the SDT provide additional clarify for the phrase “anticipated Emergency”. Supporting TOP Standard:TOP-002-3 addresses the need for a TOP to perform an Operational Planning Analysis and when appropriate to develop a plan based on those results. That plan must be communication to Registered Entities that have to perform an action. *(See ATC’s Comments to TOP-002)* Because TOP addresses next day studies we believe that there is no need for this requirement to also cover Operational Planning Analysis. Clarifying questions: Does the Operational Planning Analysis have to be performed by the TOP itself? (Situation: Currently MISO does a next day study for its footprint. Could that qualify as an Operations Planning Analysis being performed, or does each TOP have to perform its own next day study.) Requirement 3: “... based on its assessment of its Operational Planning Analysis. ”Issue 2: When is notification required to take place? ATC believes that the primary responsibility of the system operator is to address the actual (real-time) Emergency and then when appropriate follow up with the RC and other TOP’s. The only exception is when the TOP has to issue a Reliability Directive which would be issued in response to the situation. Requirement 5: ATC believes that the second sentence should be deleted because all it is attempting to do is provide examples. The first sentence provides enough clarity, so that the second sentence is not needed and may result in more confusion. Requirement 6: Issue 1: Who qualifies as an “affected entity”? If the entity is not registered with NERC how can NERC verify that coordination took place? Does this mean that a TOP, BA and GOP would have to contact customers if the planned outage could affect them? How affected does an entity have to be in order to trigger coordination? Measure 6 states that the TOP, BA and GOP must coordinated “among impacted reliability entities” but there does not exist a definition of “reliability entities”. This standard should clearly set the expectations as to who does the TOP, BA and GOP have to coordinate with and not

Organization	Yes or No	Question 1 Comment
		make the requirement so broad to allow questions about who was involved in the coordination. Issue 2: It is not clear as to when a planned outage of telemetering and control equipment and associated communication channels has to be coordinated. Requirement 7: ATC believes that the term “outside” is not clear and that the SDT should either define the term or use a more appropriate term. Suggested Modification: Modification to R7: “Each TOP shall not “exceed” an identified IROL...” Requirement 8: ATC raised a question on Requirement 3 asking if each TOP has to perform its own Operations Planning Analysis. Based on the answer to that question this requirement may need to be deleted. If an Operations Planning Analysis can be performed by the RC then there would be no need for the TOP to contact the RC about the results of their own study. We believe that Requirement 2 of TOP-002-3 covers Operational Planning Analysis so there is no need to have a duplicate requirement.ATC is unclear as to what this requirement is attempting to achieve. Is this requirement simply saying that the TOP has to share their system operating limits with the RC? If that is the case we believe that the requirement should be rewritten to provide that specific clarity. Suggested Modification: The TOP shall inform the RC of all BES System Operating Limits (SOLs) that support local area reliability. Requirement 9: Issue 1: The proposed requirement is too restrictive because it prevents the TOP from applying loss of life assumption on its equipment. We believe that entities should be able to determine when exceeding equipment limits is appropriate based on the situation and equipment. Suggested Modification:- The TOP may exceed (real-time) a SOL for a continuous duration of 30 minutes. In addition we believe that the TOP should be allowed to use the IROL Tv concept to allow an SOL to be exceeded for a continuous duration of greater than 30 minutes if they notify the RC of the longer SOL Tv. Requirement 10: It is not clear as to when the notifications must take place. Would notifying the RC following the exceedance of the IROL or SOL be okay, or, must the TOP contact the RC prior to taking action in order to be compliant with this requirement? Requirement 12:

Organization	Yes or No	Question 1 Comment
		ATC believes that this requirement is unnecessary because it is only saying that a TOP has to know what is going on with its system. In order to be compliant with the other requirements in this standard a TOP understands that by default they must monitor as appropriate its system. The challenge this requirement introduces is that it is so broad that demonstration of compliance is overly burdensome. In addition this requirement is unclear as to what and how often the TOP has to monitor, or have access to information to demonstrate compliance. Questions: • If a TOP has a 4 second scan rate for EMS data and if a single data scan is missed or an error occurs at a single point does this mean that the TOP is non-compliant? • If an entity uses information on a RC website about planned outages and for some time that system is unavailable for any length of time will the TOP be non-compliant because they don't have access to information? • What does the requirement mean by the phrase "conditions and Facilities"? • Does this mean that the ROP has to monitor breaker statues, switch statues, transformer temperatures, wind conditions and ambient temperatures? • Proposed suggestion: ATC believes that this requirement should be deleted. Requirement 13: This requirement will reduce reliability because it will force TOP's to use the smallest base case model to perform its Operational Planning Analysis. We believe our statement is accurate because it requires the TOP to have an EMS model that matches the Operational Planning Analysis model. So if an entity performs off-line studies (non EMS studies) that use the Eastern interconnection then they must also monitor or have accession to information for the Eastern Interconnection. Since access to all if information is highly unlike or unnecessary to gather the TOP will have to use the model contained in their EMS to perform Operational Planning Analysis. Although this may not necessary be a bad thing a TOP will loss the benefits of using the larger model to perform Operational Planning Analysis. If the RC performs the Operational Planning Analysis then by this requirement does the TOP have to monitor everything in the RC's Operational Planning Analysis model? Suggested Modification: ATC believes that this requirement should be deleted.

Response: "Reliability Directive" is not meant to equate to urgency of a situation; rather, it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the

Organization	Yes or No	Question 1 Comment
System Operator. The exact words needed to affect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made. Requirement 3 – Issue 1: First, Requirement R3 only refers to the assessment of the OPA. The SDT offers what the words were meant to convey: A Transmission Operator is mandated to contact its Reliability Coordinator about System conditions shown in the OPA that will cause the Transmission Operator to initiate Emergency procedures, or may cause the Transmission Operator to initiate Emergency procedures. Requirement R3 extends that contact to other Transmission Operators that either were identified in the OPA as being affected or the Transmission Operator knows are being affected. The wording is crafted to eliminate the possibility that an auditor would find the TOP non-compliant when another Transmission Operator is not previously identified in any study or any procedure. The words state that if you 'know or expect' impacts on someone, then you must contact them to prepare them for the conditions; but if you don't know or expect an entity to be affected, then the requirement does not apply. Requirement 3 links all of the prior conditions to the OPA. That is intended to provide an explicit measure and to mitigate the worry that Requirement R3 applies to any and all impacts. To delete the language about "anticipation" would change the requirement from a requirement that uses an OPA as a reference point, to a requirement that has no reference point. As written, the Transmission Operator can document what it "anticipated." As ATC proposes, the Transmission Operator must satisfy an auditor's subjective view of "anticipate". No change made. There is no requirement that the Transmission Operator do the OPA. The only requirement is that the OPA be performed if the other requirements (e.g., impact on others) can be carried out. No change made. There is no requirement on timing. The requirement is written to accommodate ATC's concern that real-time actions are more important than procedural mandates. The ATC question seems to be requesting the requirement be converted into an administrative procedure. There is no one correct time period to inform others. The requirement is written to recognize that conditions not rules must dictate the response. The Transmission Operator would only be hurting itself if it did not tell others that the Transmission Operator needed them to relieve a problem. If the impact took down the System, the Transmission Operator as well as its neighbor would be hurt. No change made. Requirement 5 – The SDT worded this requirement to comply with a FERC Order 693 directive. No change made. Requirement 6 – Issue 1: The SDT has revised the wording of the requirement to address your comment as well as those of others. Issue 2: planned = any time ahead of fact. No change made. **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities. Requirement 7 - The term "outside" was used to recognize that there are both upper and lower limits. No change made. Requirement 8 - The ATC suggestion that the Reliability Coordinator, not the Transmission Operator, do the OPA would impose a regional control of Facilities. Today, Transmission Operator s plan, commit, and operate their Facilities for their regulatory defined areas. Those "local" plans are fed to the Reliability Coordinator, which has the right to adjust the local plans based on wide-area considerations. The current Industry approach incorporates local reliability margins. That process is much different than the one ATC is proposing. The ATC proposal would in effect impose the Reliability Coordinator's reliability perspective on all local areas (now the Reliability Coordinator imposes its control over the performance – actual and expected-- of the areas not over the commitment or local margins). The ATC model of total Reliability Coordinator control is not prohibited by the current requirement, but it does not mandate the ATC model. Requirement R3 says nothing about SOLs; Requirement R3 merely requires the Transmission Operator to share advanced warning information (warnings		

Organization	Yes or No	Question 1 Comment
obtained via the OPA) with its Reliability Coordinator. That does not mean the Transmission Operator need not share information that it obtains normally for from other sources. It just says if you predict an emergency based on the OPA, then give others a "heads-up." No change made. Requirement 9 - The debate around SOLs centers on some people's conception that there is one and only one "limit." There is another perspective that forms the basis of this standard and that is both IROLS and SOLs can be a series of values: A lower value that can be used forever, and higher values that can be sustained for shorter time durations. Requirement R9 is only "too prescriptive" if the former concept (of one limit) is used. Requirement R9 is not prescriptive at all. If the Transmission Operator has only one limit, then that value must be used. But if the Transmission Operator has a series of curves, Requirement R9 does not preclude switching magnitude limits from one value to another (and of course switching T_v s from one value to another). However, if the Transmission Operator places a magnitude and a duration on the limit-set, then that limit set must be respected. If ATC uses a 500 MW continuous rating than as long as the flow is 500 MW or less there is not issue. But if the flow exceeds 500 MW, then ATC would either change the limit-set or correct the flow. It must be understood that the Transmission Operator itself has decided (via Requirement R8) that it wants the Reliability Coordinator to handle this particular limit in the same way that the Reliability Coordinator handles IROLs. Why would a Transmission Operator designate a Facility in Requirement R8 and then want to ignore it? No change made. Requirement 10 - There is no requirement on timing. The requirement is written to accommodate ATC's concern that Real-time actions are more important than procedural mandates. The ATC question seems to be requesting the requirement be converted into an administrative procedure. There is no one correct time period to inform others. The requirement is written to recognize that conditions not rules must dictate the response. The Transmission Operator would only be hurting itself if it did not tell others that the Transmission Operator needed them to relieve a problem. If the impact took down the System the Transmission Operator as well as its neighbor would be hurt. No change made. Requirement 12 & 13 – These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
Michael Gammon	No	Requirements R3 & R5 requires TOP's to notify all other "affected" or have an "adverse reliability impact" TOP's of an emergency condition. The terms "affected" and "adverse reliability impact" is a debatable condition and subject to interpretation. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Recommend the requirement be modified to alert other TOP's whenever a TOP in an emergency condition becomes aware of operating conditions that would result in exceeding an SOL or IROL operating limits under N-1 contingency conditions for other TOP facilities. Modifications for these two requirements will result in subsequent changes to the Measures and VSL's for requirements R3 & R5.
Response: Requirement 3 - Requirement R3 is written as an advanced warning and is centered on the OPA results. Requirement R3 is about forecasted (OPA) "expectations". If the Operational plans 'forecast' that the next day's operation will (or is likely) to result in Emergency operations, Requirement R3 says to tell the Reliability Coordinator and the other Transmission Operator s who are explicitly shown to be involved (e.g., they may be needed to carry out a part of the Emergency Operating procedures – such entities are "known" to be involved). On the other hand, there may be "indications" that other Transmission Operators may or may not be involved. Since such an evaluation is indeed subjective (i.e., based on the Transmission Operator's perspective), the requirement is written to bias the Transmission Operator to informing the "expected to be affected" Transmission Operators. You are correct that this part of the requirement is problematic for auditors who are seeking to punish a Transmission Operator. But the standard is not written for punishment purposes, it is written to drive proper actions. The		

Organization	Yes or No	Question 1 Comment
proper action is "when in doubt tell the other party." An auditor cannot (and should not attempt to) measure such marginal/subjective conditions. The SDT believes the words are consistent with NERC's position to write standards that support reliability. No change made. Requirement 5 - Requirement R5 is written as an implementation (of Emergency Operating Procedures) requirement. Requirement R5 is about real-time expectations. If a Transmission Operator knows that its Emergency operations will adversely impact another Transmission Operator in Real-time, then that Transmission Operator is required to inform the latter entity. As with Requirement R3, there is a reliability objective and there is a measureable event. There is also subjectivity in categorizing the "intent." If a Transmission Operator states in its logs or other documents that act X will impact Transmission Operator "A," then that Transmission Operator "knows" and is therefore obligated to follow up; likewise, if a Transmission Operator in its logs or other documentation states that act Y is likely to impact Transmission Operator 'A," then that Transmission Operator is obligated to follow up. A Transmission Operator can supply documents to prove that it followed up. Proving a negative is not expected by this requirement. No change made.		
Leland McMillan	Yes	NorthWestern Energy appreciates this chance to comment. NorthWestern supports the definition of "Reliability Directive" as indicated in the Definitions section. R13 could be clarified to specify the exact types of information about conditions and facilities identified that the entity must have access to. Also, NorthWestern seeks clarification as to why the requirement mandates that the TOP shall have this information "within any Transmission Operator Area"? Perhaps the intent of the requirement is geared towards TOPs obtaining operating information pertaining to their own TOP area, regardless of which TOP area it is actually physically located in? NorthWestern requests that the drafting team consider flexibility in the implementation timelines of this standard. Compliance with this standard might require Transmission Operators to acquire/arrange for Operational Analysis and planning simulation tools not currently required by any FERC approved standards.
Response: Requirement 13 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Regarding the data -- the requirement as written is linked to the respective Transmission Operator's Operational Planning Analysis process. If the respective Transmission Operator requires a piece of data for that analysis, then Requirement R12 mandates that the Transmission Operator get information about the item in question. To mandate every item would either be too much for some Transmission Operators and too little for others. There is no one analysis format that was found to fit all Transmission Operators. Addressing the FERC Order with a minimum list would violate FERC's other requirement that NERC standards not reflect minimum common denominators. This requirement is designed to require Transmission Operators to follow up on any items that are highlighted in the Transmission Operator's plans. If the operational plan points to a situation (e.g., a Facility in another area) then the Transmission Operator must make accommodations to obtain information about that facility. That does not mean that the Transmission Operator must have an RTU feed from the Facility, but it does mean that the Transmission Operator must make arrangements to get the information/communications somehow (e.g., having the neighbor report a line flow periodically, or report when the flow exceeds some predetermined value…). The context of the requirement is that if a Transmission Operator needs information to do its reliability studies then that		

Organization	Yes or No	Question 1 Comment
Transmission Operator should get the information even if that information is from a non-adjacent entity. Take for example a 3000 MW DC line between two Interconnections. That line could carry a 3000 MW interchange schedule. The loss of that line could affect a third party Transmission Operator with an impact greater than the Transmission Operator's largest Contingency. In such a case, it would be necessary for all parties to agree to how much interchange will be allowed. Moreover the non-adjacent Transmission Operator may want to be informed of what the loading of the DC line is so as to maintain the security of its own Transmission Operator area. This example would also involve Reliability Coordinators, but the point is that if there is a need than the Transmission Operator is obligated to get sufficient information (not metering just information – like a phone call) to ensure that the System is reliable. No change made. The requirements are written from the perspective of the Transmission Operator and "its" tools; not from the perspective of an auditor and what the audit believes is the right tool. The requirements do not impose common tools or data or lists (see comments to others who want such lists ostensibly to protect themselves). The requirements are written to recognize that a Transmission Operator may be as small as one line or as large as half an Interconnection. The tools and data and procedures must of necessity be different and these requirements respect that diversity. No change made.		
Northeast Power Coordinating Council	Yes	In R9, to clarify the requirement to operate below a System Operating Limit (SOL), "outside" should be replaced with the wording "at or above".
Response: The term "outside" was used to recognize that there are both upper and lower limits. To insert "at or above" could be construed by some people as not including "at or above." No change made.		
Darryl Curtis	Yes	
Dan Rochester	Yes	We applaud the SDT of its positive response to our previous comments regarding the lack of monitoring of and requirement to operate within SOLs. Although the revisions do not go all the way to ensuring operating within all SOLs, and mitigating exceedances as they occur, the revised standard goes a long way in meeting that general intent. We agree with all the changes to the Time Horizons, Measures, data retention and compliance elements (VRFs and VSLs).
Kasia Mihalchuk	Yes	
PacifiCorp	Yes	
Response: Thank you for your support		
Western Electricity Coordinating Council		Under R1 of the standard the word "identified" is used to describe a specific type of Reliability Directive issued by the Transmission Operator. Who performs the work or makes the identification of an "identified" reliability directive? Why under R2 is the classification not carried on to describe the RC directive such as "of its inability to

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>perform an IDENTIFIED Reliability Directive”?</td></tr>
<tr><td colspan="3">Response: As written, the Transmission Operator would “identify” an action as a Reliability Directive. No change made.

The SDT has revised Requirement R2 as suggested:

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]</td></tr>
<tr><td>Randi Woodward</td><td></td><td>Minnesota Power does not have any comments at this time.</td></tr>
</table>

2. TOP-002-3: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: The SDT edited the text box for the rationale for Requirement R1 and adjusted the wording for Requirement R3 and M3 based on industry comments to provide additional clarity and to make the intent of the SDT clear.

R3. Each Transmission Operator shall notify all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).

M3. Each Transmission Operator shall have evidence that it notified all ~~reliability~~ registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

Organization	Yes or No	Question 2 Comment
Public Service Enterprise Group Companies	No	The Rational to R1 should add language to clarify that in some circumstances the failure or unavailability of the usual tools may result in the inability to perform a complete and comprehensive analysis. Therefore the words "to the extent practicable" should be added (see below) in the last sentence after the word "able."Rationale for Requirement R1:By definition, Operational Planning Analysis includes Contingency analysis. By stating this Requirement in this manner, the SDT is stating that a Transmission Operator must have analysis tools or procedures to perform the Operational Planning Analysis (or has contracted the service). Since the Requirement does not mandate how the analysis is completed, if tools are used, the Transmission Operator must be able to the extent practicable to complete the analysis even if those tools are not available.
Response: What is required is to have an effective Operational Planning Analysis. How that is provided is up to the entity. Introducing phrases and qualifiers such as “to the extent practicable” would result in something that cannot be measured. No change made.		
Bonneville Power Administration	No	R2 Although an entity does not plan to operate above the SOL, a contingency may cause an short SOL excursion until planned mitigation action is completed within the Tv (allowable violation time limit). Non-electrical people could get confused by this distinction. Suggest clarifying SOL as intended to be path loading limits and/or local area transmission service support limits, (the BES is a big system with lots of ratings, it can also mean voltage limits in addition to line and path limits).
Response: T_v is defined only for Interconnection Reliability Operating Limits (IROL). While the SDT agrees with your statements that short excursions may occur within an applicable time which respects Equipment Ratings, that time may vary significantly from one SOL to another. The suggestion to clarify SOL as intended to be path loading limits or local area Transmission service support limits is problematic as those terms are not universal in use nor are they defined. Requirement		

Organization	Yes or No	Question 2 Comment
R2 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). No change made.		
SERC OC Standards Review Group	No	In R2 and M2, what is the meaning of "local area reliability" and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word "supporting' could be replaced by the phrase "necessary for".
Response: IROLs are the subset of SOLs that "…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages." The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Reliability Coordinator or Transmission Operator has determined to be important to supporting reliability in a local area. No change made.		
Southern Company Transmission	No	Southern's comments: The current NERC Glossary definition of Operations Planning Analysis does not explicitly include contingency analysis. Unless the SDT is modifying the definition of Operations Planning Analysis to include contingency analysis, we recommend that R1 be re-expanded to include the expectation of performing contingency analysis. Regarding R2 and M2, a TOp should not plan to operate beyond any SOL limit - regular or one that "is supporting local reliability." Otherwise, why should it be classified as an SOL? SERC's comments: Southern participated in developing these comments and support them. In R2 and M2, what is the meaning of "local area reliability" and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word "supporting' could be replaced by the phrase "necessary for".
Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue: R2 and M2**:** IROLs are the subset of SOLs that "…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages." The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Reliability Coordinator or Transmission Operator has determined to be important to supporting reliability in a local area. No change made. SERC's comments: Knowing SOLs is important for situational awareness (know where you are and where you expect to operate) and for determining whether Adverse Reliability Impacts may result from exceeding them. If such an adverse impact is predicted, there is potential that the SOL is indeed an IROL. If it does		

Organization	Yes or No	Question 2 Comment
not meet the qualifiers as an IROL, but it is important to a local area, the Transmission Operator (or a Reliability Coordinator, for that matter) may designate such an SOL for the Reliability Coordinator to include in the limits that must be honored and mitigated as soon as possible, but no longer than 30 minutes. No change made.		
MRO's NERC Standards Review Subcommittee	No	The rationale box needs to be clarified. If the drafting team meant for entities to have a primary set of tools / procedures and backup set as well, please clarify that. "By definition, Operation Planning Analysis includes Contingency analysis" is not accurate. The definition in the Glossary of Terms mentions nothing of contingency analysis. It mentions known transmission and generation facility outages, but that has nothing to do with contingency analysis, which includes a study of unknown events to occur on current system conditions. Therefore, the requirement should read "Each Transmission Operator shall have an Operational Planning Analysis that incorporates potential single contingency events." Is "plan" in requirement R2 a noun or verb? It appears to read as if it is a verb, which implies no documented action would be necessary. If intended, it should read "Each Transmission Operator shall develop a plan...." This flows much better with what the intent of R2 is trying to say.
Terry Harbour	No	The rationale box needs to be clarified. If the drafting team meant for entities to have a primary set of tools / procedures and backup set as well, please clarify that. "By definition, Operation Planning Analysis includes Contingency analysis" is not accurate. The definition in the Glossary of Terms mentions nothing of contingency analysis. It mentions known transmission and generation facility outages, but that has nothing to do with contingency analysis, which includes a study of unknown events to occur on current system conditions. Therefore, the requirement should read "Each Transmission Operator shall have an Operational Planning Analysis that incorporates potential single contingency events." Is "plan" in requirement R2 a noun or verb? It appears to read as if it is a verb, which implies no documented action would be necessary. If intended, it should read "Each Transmission Operator shall develop a plan...."
Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue. 'Plan' in Requirement R2 is a verb. It is the process of putting together the operations plan for whatever timeframe is applicable. Part of that process includes the performance of an Operational Planning Analysis. No change made.		
Joylyn Faust	No	The proposed standard which indicates the TO shall "notify" reliability entities as to "their role" appears to be bolstering the authority of the TO. During real time events the TO should have authority to issue directives, however on a planned basis TOs should coordinate, not dictate the role of the entities. On a planned basis,

Organization	Yes or No	Question 2 Comment
		input from the involved entities will result in a more reliable system.
Response: The requirement, following the coordination required to develop an operating plan, is to notify the entities that have roles in the operating plan, and what those roles are. For example, those entities may have actions to perform, or they may have Facilities that will be impacted by actions taken by others. Reliability Standard TOP-002-3 pertains to Operations Planning. The execution of the operations plans developed within the requirements of TOP-002-3 is covered in other standards. The SDT agrees that input from the involved entities will result in a more reliable System, but once that input has been received and a plan has been put into place, those entities with roles in the plan must be notified as to what are those roles. No change made.		
Jon Kapitz	No	R2. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. Xcel Energy believes this requirement is confusing as written. It appears to want to include all SOLs. If so, why not just state as such? It could be simply stated as "...IROLS and SOLS..." R3. Each Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). Xcel Energy believes this should be limited to just entities within the TOP's own area.
Response: IROLs are the subset of SOLs that "…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages." The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Transmission Operator has determined to be important to supporting reliability in a local area. Requirement R2 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). No change made. Knowing SOLs is important for situational awareness (know where you are and where you expect to operate) and for determining whether Adverse Reliability Impacts may result from exceeding them. If such an adverse impact is predicted, there is potential that the SOL is indeed an IROL. If it does not meet the qualifiers as an IROL, but it is important to a local area, the Transmission Operator may designate such an SOL for the Reliability Coordinator to include in the limits that must be honored and mitigated as soon as possible, but no longer than 30 minutes. No change made.		
Howard Rulf	No	Rationale for Requirement R1: Operational Planning Analysis does not include Contingency analysis "by definition". "Contingency analysis" does not appear in the definition of Operational Planning Analysis. R2: Since any SOL is to "ensure operation within acceptable reliability criteria" this requirement requires that the TOP include all SOLs in their "plan". R3: When is this notification to take place? Since this analysis starts taking place as much as 12 months in

Organization	Yes or No	Question 2 Comment
		advance, as the plan changes over time there could be multiple conflicting notifications.

Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue.

R2 - IROLs are the subset of SOLs that "…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages." The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Reliability Coordinator or Transmission Operator has determined to be important to supporting reliability in a local area. Knowing SOLs is important for situational awareness (know where you are and where you expect to operate) and for determining whether Adverse Reliability Impacts may result from exceeding them. If such an adverse impact is predicted, there is potential that the SOL is indeed an IROL. If it does not meet the qualifiers as an IROL, but it is important to a local area, the Transmission Operator (or a Reliability Coordinator, for that matter) may designate such an SOL for the Reliability Coordinator to include in the limits that must be honored and mitigated as soon as possible, but no longer than 30 minutes. No change made.

R3 – After the Transmission Operator runs an Operational Planning Analysis and determines another entity as having a role in their plan and before the affected entity has to take action, they should notify the affected entity. No change made.

Organization	Yes or No	Question 2 Comment
RoLynda Shumpert	No	In "Consideration of Comments on First Draft of Revised TOP Standards Real-Time Operations - Project 2007-03," p77, #6 response, March 26, 2009, it was stated that "reliability entities" is not a defined term. In addition, in "Consideration of Comments on Second Draft of Standards for Real-Time Operations (Project 2007-03)," pp 64-65, August 25, 2009, a response is given to Xcel Energy's comment that the phrase reliability entities needs definition that "reliability entities are the entities certified by NERC as such." SCE&G believes that it is unclear what is meant by "certified by NERC as such" and would appreciate that these entities be spelled out as it relates to these Standards. It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.

Response: Reliability entities: The SDT has changed the wording to 'registered entities.'

R3. Each Transmission Operator shall notify all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).

The SDT has checked all the references and made corrections as needed.

Organization	Yes or No	Question 2 Comment
Greg Rowland	No	R2, M2 and R2 VSL - Replace the phrase "supporting its local area reliability" with the phrase "having an Adverse Reliability Impact". This adds clarity regarding which SOLs must be addressed in the TOP's plan. R3 VSL - The mixing of numbers with percentages and the phrase "whichever is less" in these VSLs is

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>confusing. For example, if there are four affected entities, and the TOP does not notify one of the four, then that is one entity, or 25% of the total. What does “whichever is less” mean? Is that a Lower or Severe violation? Conversely, if there is only one affected entity and the TOP does not notify that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation?</td></tr>
<tr><td colspan="3"> Response: R2, M2, and R2 VSL: Replacing the phrase “supporting its local area reliability” with the phase “having an Adverse Reliability Impact” would be inappropriate because the definition of Adverse Reliability Impact clearly indicates impact to a widespread area of the BES, not just a local area. No change made. R3 VSL: The mixing of numbers and percentages is standard verbiage for VSLs. It is designed to allow for size differences in applicable functional entities. ‘Whichever is less’ means simply that you use the option that is less numerically. No change made. </td></tr>
<tr><td>Michael Lombardi</td><td>No</td><td> The rationale box for Requirement R1, indicates that TOP must be able to complete analysis even if the tools that are used are not available. It is not clear how contingency analysis would be performed if study tools are not available. What if day ahead study tools are part of an Energy Management System (EMS) which is a high reliability redundant system with an independent system at a back up facility? Is the rational box verbiage suggesting one would need to postulate the loss of a redundant EMS as well as its back up facility? Please clarify what is to be accomplished pursuant with R1. The term “Operational Planning Analysis”, is capitalized to identify it as a defined term yet the NERC Glossary of Terms (updated 4/20/2010) indicates that the term has not been FERC approved. (See additional write up in Question 1 comment) </td></tr>
<tr><td colspan="3"> Response: What is required is to have an effective Operational Planning Analysis. How that is provided is up to the entity. The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue. The following definition is taken from the NERC Glossary of Terms Used in the Reliability Standards: “Operational Planning Analysis: An analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).” This definition has been approved by the NERC BOT but not yet approved by FERC. NERC BOT approval gives the definition operational authority. No change made. </td></tr>
<tr><td>Saurabh Saksena</td><td>No</td><td>TOP-001 R8 & TOP-002 R2 - When referencing SOLs both say something like "SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability...". National Grid suggests deleting “...which, while not IROLs...”.,</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3">Response: The wording “while not IROLs” was inserted to make clear that not all limits have adverse reliability impacts, but that some limits that do not have reliability impacts can still be held to a higher standard of operations - as long as those limits are identified.

An SOL that has adverse reliability impacts is by definition an IROL. Requirement R8 says that if it isn’t an IROL and you want the limit to be controlled in the same way as an IROL then tell the Reliability Coordinator which limits you want. [Note what all this means –when running its planning and/or operating analysis, the Reliability Coordinator does not find the said limit as causing any BES problems – thus the Reliability Coordinator is not concerned with the said limit. The Transmission Operator however, wants, or is required by some other authority, to treat the said limit as if that limit had BES implications. Such information must be conveyed by the Transmission Operator to the Reliability Coordinator.] Thus, inserting the proposed text will not accomplish the intent of the requirement. No change made.</td></tr>
<tr><td>Catherine Koch</td><td>No</td><td>R1/R2 - The side-bar indicates that Contingency analysis is included Operational Planning Analysis by definition. The definition of Operational Planning Analysis, however, does not discuss or even mention Contingency analysis. Recommend a revision to the definition of Operational Planning Analysis to clarify that such an analysis does include Contingency analysis.

R2 - See comments regarding identified SOLs under requirement R8 of TOP-001-2 above.</td></tr>
<tr><td colspan="3">Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue.

R2: See response to comments regarding identified SOLs under requirement R8 of TOP-001-2.</td></tr>
<tr><td>Jason Shaver</td><td>No</td><td>Rational Box: The SDT states that by definition Operational Planning Analysis includes Contingency Analysis. ATC does not agree with this statement and therefore we requests that the SDT removed this statement. Operation Planning Analysis: “An analysis of the expected system condition for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generation outages, equipment limitations, etc.).”The definition does not specifically call out contingency analysis but is specific that an Operations Planning Analysis is a next day study which can be performed any time from a day ahead to as much as 12 months ahead.

Time Horizon: In TOP-001-2 Requirement 2 the SDT calls on Operations Planning Analysis to be performed and identifies it as either a Same-Day Operations, Real-Time Operations Time Horizon requirement. In TOP-002-3 Requirement 1 the SDT is calling for Operations Planning Analysis to be performed and identifies it as a Operations Planning Time Horizon. ATC finds it very confusing that the SDT is using this defined term in multiple Time Horizons and believes that a single time horizon be used for this term.</td></tr>
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Organization	Yes or No	Question 2 Comment
		Requirement 1:If a TOP were to perform an Operations Planning Analysis for TOP-001-2 then what different Operations Planning Analysis would a TOP have to do be in compliance with Requirement 1 of TOP-002-3? Requirement 2: ATC believes that Requirement 2 (TOP-002-3) conflicts with TOP-001-2 Requirement 9. Requirement 9 in TOP-001-2 allows a TOP to exceed an SOL for a continuous duration of 30 minutes but that same allowance is not provided in requirement 2. (Note: see ATC's comment to Question 1 requirement 9.) ATC believes that the same continuous duration time provided in Requirement 9 of TOP-001-2 be allowed in Requirement 2. Requirement 3: ATC believes that additional clarity is needed around the use of the term "role". We believe that this requirement is calling for TOP's to contact other Registered Entities if they have an "action" to perform in the plan. Is ATC's understanding of the term "role" consistent with the SDT's understanding? A TC also believes that the phrase "reliability entities" should be replaced with Registered Entities.

Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue.

Time Horizon: Time Horizon refers to the time period for mitigating a violation to the requirement, not an operating timeframe. TOP-001-2, Requirement R2 does not address Operational Planning Analysis. Requirement R3 does mention Operational Planning Analysis and does apply to the Same Day Operations and Real-Time Operations Time Horizons. TOP-002-3 pertains to Operations Planning, while TOP-001-2 pertains to multiple Time Horizons. No change made.

Requirement 1: If the Operational Planning Analysis performed includes all the relevant expected conditions, it may be appropriate for a next-day analysis, same-day analysis, or Real-time analysis. However, if any actual System conditions differ from the assessed conditions, the entity must decide whether the analysis continues to cover the potential reliability impacts. If not, then the analysis should be updated. No change made.

Requirement 2: TOP-002-3, Requirement R2 pertains to Operations Planning. TOP-001-2, Requirement R9 pertains to Real-time Operations. The assessment of an Operational Planning Analysis in Operations Planning may "predict" that an SOL or IROL will be exceeded, but it does not predict a duration of that exceedence. In Real-time Operations, the entity must be taking mitigation actions whenever an exceedence is identified. If that exceedence cannot be mitigated within 30 minutes, then the exceedence becomes a violation. No change made.

Requirement 3: The requirement, following the coordination required to develop an operating plan, is to notify the entities that have roles in the operating plan, and what those roles are. For example, those entities may have actions to perform, or they may have Facilities that will be impacted by actions taken by others. No change made.

Reliability entities: The SDT has changed the wording to 'registered entities'.

R3. Each Transmission Operator shall notify all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).

Organization	Yes or No	Question 2 Comment
Jonathan Appelbaum	Yes	"Operational Planning Analysis" is not a defined term in the NERC Glossary and a proposed definition is not included in the Draft Standard. TOP-001 and TOP-002 have capitalized the term indicating a definition. TOP-002 information box says "by definition Operational Planning Analysis includes Contingency Analysis."
Response: The following definition is taken from the NERC Glossary of Terms Used in the Reliability Standards: "Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." This definition has been approved by the NERC BOT but not yet approved by FERC. NERC BOT approval gives the definition operational authority. No change made. The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue.		
Dan Rochester	Yes	Again, we applaud the SDT of its positive response to our previous comments regarding the lack of consideration to SOLs in operational planning. Although the revisions do not go all the way to ensuring TOPs plan their operations to respect all SOLs, the revised standard goes a long way in meeting that general intent. We agree with all the changes to the Time Horizons, Measures, data retention and compliance elements (VRFs and VSLs).
IRC Standards Review Committee	Yes	No comment at this time. (The YES box was inadvertently checked, which we are unable to de-select)
Northeast Power Coordinating Council	Yes	
Michael Gammon	Yes	
E.ON U.S.	Yes	
Midwest ISO Standards Collaborators	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
Dominion	Yes	
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	Yes	
Kasia Mihalchuk	Yes	
Leland McMillan	Yes	
Richard Kafka	Yes	
Response: Thank you for your support.		
Randi Woodward		Minnesota Power does not have any comments at this time.

3. TOP-003-1: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: No comments were received that required contextual changes to the requirements. Some semantic changes were made for additional clarity to Requirement R1 and the Measures.

R1. Each Transmission Operator and Balancing Authority shall ~~have~~ create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

R1, Part 1.1, bullet #1 - Long term outages of Bulk Electric System (BES) equipment~~, as specified by the Transmission Operator or Balancing Authority~~

R1, Part 1.1, bullet #2 - Operating parameters for equipment of the BES and at voltage levels lower than the BES~~Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority~~

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

Organization	Yes or No	Question 3 Comment
SERC OC Standards Review	No	We believe that R5 is redundant to R4 if the Transmission Operator is added to R4.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>Group</td><td></td><td></td></tr>
<tr><td>Dominion</td><td>No</td><td>It is not clear how the data provision obligations of BAs under requirement R4 are different from their obligations under R5. We therefore suggest that TOP be added to R4 and that R5 be removed.</td></tr>
<tr><td colspan="3">Response: The SDT felt it appropriate to distinguish the individual aspects of the data requirements. Requirement R1 notes that data requirements will be established by the Transmission Operator and Balancing Authority. Requirement R2 covers the Transmission Operator’s responsibility to make the requirements known. Requirement R3 does the same for Balancing Authorities. Requirement R4 requires that other entities respond accordingly to the requests for data. And Requirement R5 requires the Transmission Operators and Balancing Authorities to share that data with other Transmission Operators and Balancing Authorities that need the data. Clarity in the requirements, especially with regard to specific roles and responsibilities of involved entities was the goal. Layered in this manner, it provides a control for data requests to be made through the Balancing Authority or Transmission Operator for the area, rather than having Transmission Operators or Balancing Authorities requesting data from non-Transmission Operators or non-Balancing Authority entities within another area without also assuring the data was known and provided to the host Transmission Operator or Balancing Authority. This may have been done through other approaches but the SDT chose this approach to achieve the desired clarity. No change made.</td></tr>
<tr><td>Southern Company Transmission</td><td>No</td><td>Southern's comments:M4 and M5, there should be allowance for outstanding requests that are still within the deadline as defined in R1.4.

SERC's comments: Southern participated in developing these comments and support them We believe that R5 is redundant to R4 if the Transmission Operator is added to R4.</td></tr>
<tr><td colspan="3">Response: The SDT presumed the meaning was clear that outstanding requests referenced only those which have exceeded the time to respond and agrees that additional clarity is required. Revisions were made to Measures M4 & M5.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled <u>and are outside of the deadline in Requirement R1, Part 1.4</u>.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled <u>and are outside of the deadline in Requirement R1, Part 1.4.</u>

The SDT felt it appropriate to distinguish the individual aspects of the data requirements. Requirement R1 notes that data requirements will be established by the Transmission Operator and Balancing Authority. Requirement R2 covers the Transmission Operator’s responsibility to make the requirements known. Requirement R3 does the same for Balancing Authorities. Requirement R4 requires that other entities respond accordingly to the requests for data. And Requirement R5 requires the Transmission Operators and Balancing Authorities to share that data with other Transmission Operators and Balancing Authorities</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td colspan="3">that need the data. Clarity in the requirements, especially with regard to specific roles and responsibilities of involved entities was the goal. Layered in this manner, it provides a control for data requests to be made through the Balancing Authority or Transmission Operator for the area, rather than having Transmission Operators or Balancing Authorities requesting data from non-Transmission Operators or non-Balancing Authority entities within another area without also assuring the data was known and provided to the host Transmission Operator or Balancing Authority. This may have been done through other approaches but the SDT chose this approach to achieve the desired clarity. No change made.</td></tr>
<tr><td>MRO's NERC Standards Review Subcommittee</td><td>No</td><td>Remove “at the discretion of the Transmission Operator or Balancing Authority” in R1-1.1. The TO and BA are the entities creating the specification, which already implies that any needed parameters are at their discretion. Overall clarification seems necessary on this bullet as well (R1-1.1).

Why specifically address equipment of voltage levels below BES levels? Does this exclude equipment rated 100 kV and above?

Replace “Real-time monitoring” with “Real-time Assessment” as this is an actual term in the NERC Glossary of Terms. This would follow a similar format to the “Operational Planning Analyses”.</td></tr>
<tr><td>Terry Harbour</td><td>No</td><td>Remove “at the discretion of the Transmission Operator or Balancing Authority” in R1-1.1. The TO and BA are the entities creating the specification, which already implies that any needed parameters are at their discretion. Overall clarification seems necessary on this bullet as well (R1-1.1).

Why specifically address equipment of voltage levels below BES levels? Does this exclude equipment rated 100 kV and above?

Replace “Real-time monitoring” with “Real-time Assessment” as this is an actual term in the NERC Glossary of Terms. This would follow a similar format to the “Operational Planning Analyses”.</td></tr>
<tr><td colspan="3">Response: The SDT was careful to be explicit and specifically clear in the requirements. However, the comment does point out an opportunity for additional clarification.

R1, Part 1.1, bullet #1 - Long term outages of Bulk Electric System (BES) equipment~~, as specified by the Transmission Operator or Balancing Authority~~.

R1, Part 1.1, bullet #2 - Operating parameters for equipment of the BES and at voltage levels lower than the BES~~Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority~~.

The SDT believes that the wording is correct as stated. No change made.</td></tr>
<tr><td>L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson</td><td>No</td><td>R1.1 - The phrase ‘to be exchanged’ seems to be unnecessary.

M2 and M3 - These measures allude to evidence of information actually being distributed, yet some companies make information available to entities through website posting or other public forums. Please</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		include showing proof of availability of information to an entity as an option in these measures. M4 - The last sentence should be revised to match the last sentence of M5. Consider rewording both M4 and M5 as follows: "The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled." The R2 and R3 VSLs have percentage approaches, but the R4 and R5 VSLs are binary, even though there are multiple elements to data specifications referred to in R4 and R5. All four of these requirements should have percentage approaches. Similarly, there are requirements for the RC (in IRO-010) to document data specifications. The associated IRO-010 R1 and R2 VSLs also have a percentage based approach. To be consistent, the TOP-003-2 R4 and R5 VSLs need to be changed to the percentage based approach for consistency.

Response: R1.1 – The SDT does not see that the suggested change adds any additional clarity. No change made.

M2 & M3 – The SDT has revised the measures based on your comments.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4 & M5 – Clarifications have been made to measures M4 and M5.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

R2 & R3 VSL – The SDT believes that there is a reliability-based difference to distribution of the specification versus supply of the data and that the VSLs reflect this difference. No change made.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>Style changes.Dan Rochester</td><td>No</td><td>M5: The last sentence added is in fact a requirement. Measures should not include requirement for “completeness” of the data provision, which is already implicit in R5. The extent to which the data is not fully provided should be assessed and reflected by the VSLs. Suggest to delete this sentence and as desired, expand the VSLs for R5 to make them graded according to the percentage of data not provided.</td></tr>
<tr><td colspan="3">Response: Measure M5 was changed due to industry comments. The measure created is a binary one. There are either outstanding (i.e., unfilled or unaddressed) requests for data, or there are not. The SDT can see no additional requirements added to the standard by this measure. No change made to the VSL.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.</td></tr>
<tr><td>Joylyn Faust</td><td>No</td><td>Poorly worded. According to the proposed standard the TO is supposed to “exchange” data, at its discretion, regarding equipment ratings at voltage levels below the BES. So when our TO demands HVD equipment ratings, what are we to exchange it with? Again, this standard appears to be bolstering the authority of the TO. If the TO can demand information from the DP, then the DP should have access to similar information regarding the TO’s system.</td></tr>
<tr><td colspan="3">Response: The standard is enabling the Transmission Operator to meet its reliability obligations. These obligations do not extend to the same degree or scope to the Distribution Provider. Therefore, there is not the same need for data by the Distribution Provider as there is for the Transmission Operator. The standard is appropriately establishing the levels of authority for data gathering as needed for reliability and in keeping with the established functional model. No change made.</td></tr>
<tr><td>John Fish</td><td>No</td><td>M4. "The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled." Should be removed The response to the "request for data", or an attestation that no requests have been made, should stand alone as proof of GO/GOP compliance??</td></tr>
<tr><td colspan="3">Response: Measure M5 has been changed to address industry comments.
M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.</td></tr>
<tr><td>Howard Rulf</td><td>No</td><td>TOP-003-2R1: Nowhere in NERC Standards is a TOP or BA required to perform an Operational Planning Analysis. This requirement applies to data specifications. It does not require Operational Planning Analysis.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		R1.2: Who mutually agrees to the format? The TOP and BA? A TOP or BA may have scores of different entities with Facilities within their boundaries. Is this requiring data format agreements with scores of other entities? The TOP and BA should be allowed to specify the data format. R4: Please explain what is meant by “satisfy the obligations of the documented specifications for data”. Please rephrase this to something more clearly understandable in the requirement. R5: Consider modifying this requirement so that the data is provided directly where possible. Data received indirectly through other entities is delayed, and there are increased chances of problems in receiving the data.
Response: R1 - This standard addresses data specifications and the obligations to provide and share data, as appropriate, and as needed, to perform reliability analyses for operations planning as required in proposed TOP-002-3. No change made. R1.2 - The requirement does not mandate “format agreements” with anyone. The mutual agreement is between the provider and the requester of the data. In this regard it is reasonable to expect that a standard format will emerge, but it is not required. The SDT believes this approach is the best way to avoid placing unreasonable format requirements into the standard. No change made. R4 – “Satisfy the obligations” means to supply the requested data according to the requirements. The SDT does not see any problem with the present wording and absent any suggested wording does not see any reason for changing the current wording. R5 – The requirement does not tell an entity how to handle data, just what data needs to be delivered. No change made.		
RoLynda Shumpert	No	It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Response: The SDT will review and correct as needed prior to the next posting.		
Greg Rowland	No	R2 and R3 VSLs - The mixing of numbers with percentages and the phrase “whichever is less” in these VSLs is confusing. For example, if there are four entities, and the TOP or BA does not distribute its data specification to one of the four, then that is one entity, or 25% of the total. What does “whichever is less” mean? Is that a Lower or Severe violation? Conversely, if there is only one entity and the TOP does not notify that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation?
Response: R2 & R3 VSL – The SDT believes that there is a reliability-based difference to distribution of the specification versus supply of the data and that the VSLs reflect this difference. No change made.		
Randi Woodward	No	Minnesota Power has the following comments for the individual requirements of the proposed Standard TOP-003-2.Requirement 1 o The time horizon doesn’t appear to match the requirement.

Organization	Yes or No	Question 3 Comment
		o The tasks required to accomplish the items listed in sub-requirements R1.1 - R1.4 also fall under the responsibility of a Reliability Coordinator, in addition to the Transmission Operator and Balancing Authority functions that are already listed in this Requirement. o The term "mutually agreeable format" is confusing and needs more definition to eliminate any confusion regarding who is required to agree on the format in sub-requirement 1.2. Requirement 4 o The way this Requirement is currently worded could leave the door open for disparate specifications. As currently written, Registered Entities are obligated to abide by all specifications regardless of feasibility or ability to implement. Minnesota Power requests more clarification regarding what is meant by "satisfy the obligations of the documented specifications for data." Requirement 5 o The way this Requirement is currently written it could open the door for a liberal interpretation of the Requirement and could result in excessive data requests in the name of "Operational Planning Analysis and Real-time monitoring." Minnesota Power suggests revising the Requirement to state that the requesting Transmission Operator and/or Balancing Authority must demonstrate a reliability need in its request for data.
Response: Time Horizon refers to the time period for mitigating a violation to the requirement, not an operating timeframe. The SDT has reviewed the current Time Horizons and feels it is appropriate. No change made. Reliability Coordinator responsibilities are covered in other standards. There may be similar data requirements for Reliability Coordinators, but that doesn't negate the need for such data by the Transmission Operators and Balancing Authorities. Additional requirements for other entities do not conflict with this requirement, which stands on its own. No change made. Mutually agreeable is self-explanatory and is between the requester and the provider of the data. No change made. "…satisfy the obligations of the documented specifications for data…" is clear in that the data, specified by the Transmission Operator or Balancing Authority in the requesting documentation must be provided as requested to satisfy the obligation. The SDT thinks this requirement is clear. No change made. Demonstrating a reliability need for data is unnecessary. There is no expectation that a Transmission Operator or Balancing Authority would request data that is unneeded. There is a burden placed onto the Transmission Operator and Balancing Authority to manage the data requested, and an expectation that data will be used and useful. It is not reasonable to expect that unneeded data will be requested as there is no incentive to make such a request, and some incentive not to do so. No change made.		
Catherine Koch	No	R1 - As indicated in the first full row on page 5 of the document "Resolution of Issues Assigned to Real-time Operations SDT (Project 2007-03)", FERC staff disagrees with the data specification approach. How does the SDT propose to deal with this disagreement? Given this disagreement and FERC's current concerns with NERC's standard approval process, what purpose does continuation of the current approach accomplish? R1.2 - The phrase "mutually agreeable format" may lead to disputes between the TOP and other entities

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>subject to the TOP’s data specification. In the event that the entities cannot agree, the TOP’s reasonable requirements should trump.

R1.4 - There should be language added that requires agreement to proposed deadline by the entity receiving the specification as there could be a need for programming work and it could be foreseen that the deadline indicated can not be reasonably met.</td></tr>
<tr><td colspan="3">Response: R1 – NERC staff believes, and the SDT concurs, that the data specification approach outlined here and in the proposed IRO standards is a more effective approach to data handling and is working with FERC staff to bring this issue to a satisfactory conclusion. No change made.

R1.2 and R1.4 - If there is a disagreement that cannot be handled by the entities involved, the SDT believes that existing conflict resolution agreements would be used to resolve the dispute. No change made.</td></tr>
<tr><td>Jason Shaver</td><td>No</td><td>Requirement 1.1: ATC believes that requirement 1.1 is unnecessary and opens up other issues and therefore should be deleted from this standard. Long-term outage information while important is not directly related to EMS data. In addition, information about facilities that operate below 100 kV is beyond FPA 215 and is beyond NERC’s jurisdiction.</td></tr>
<tr><td colspan="3">Response: It is correct that the requirement for data does indeed extend beyond EMS data. This is the intent of the requirement. This data is needed to enable appropriate operations planning for conditions (which real-time EMS scans would not represent) throughout the Operations Planning Horizon, as is the intent of the requirement. Facilities below 100 KV may have material impact to the BES and, as such, are within the scope of the requirement and must, as determined necessary by the host Balancing Authority or Transmission Operator, be included. No change made.</td></tr>
<tr><td>Michael Gammon</td><td>No</td><td>Requirement R4 may be troublesome for small Registered Entities to meet the data requirements dictated by larger Registered Entities. The is no recognition of the limitations of data exchange capability with an entity. Recommend requirement R4 be modified to include "within the data exchange capabilities of the recipient of the data specification". Modifications here would result in changes to the Measure and VSL for requirement R4.</td></tr>
<tr><td colspan="3">Response: It is not anticipated that a data request would be made for data that is not reasonably available. Nonetheless, the concept of a standard in this regard is to assure that data needed for reliable operations is made available, as appropriate. This standard incorporates the ability for Transmission Operators and Balancing Authorities to adjust data requirements to meet the needs of regional areas, while maintaining a standard. The SDT believed this approach superior to one which mandated a one-size-fits-all data requirement, which would result in either insufficient data because the standard was too weak (accommodating various levels of data gathering capabilities), or too stringent in some cases (as potentially described in this comment), thereby creating unreasonable data requests in some cases. The SDT used this approach to enable addressing the concern raised here as would not be possible in the one-size-fits-all approach. No change made.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	We commend the drafting team for attempting to manage the evidence in a way that does not require the TOP to get evidence to prove an absence of an issue, however, the following statement needs clarification to remove the double negative verbiage, "The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled." This statement might be improved by stating "The evidence shall be the Transmission Operators and Balancing Authorities requests have been met." This will allow the entity to show the requests received from other entities and the evidence that they filled those requests.
Response: The SDT has revised the measures based on your comments and those of others**.** **M4.** Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4. **M5.** Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.		
IRC Standards Review Committee	Yes	No comment at this time. (The YES box was inadvertently checked, which we are unable to de-select)
Northeast Power Coordinating Council	Yes	
Public Service Enterprise Group Companies	Yes	
E.ON U.S.	Yes	
Midwest ISO Standards Collaborators	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 3 Comment
PacifiCorp	Yes	
Jonathan Appelbaum	Yes	
Kasia Mihalchuk	Yes	
Jon Kapitz	Yes	
Michael Lombardi	Yes	
Leland McMillan	Yes	
Richard Kafka	Yes	
Saurabh Saksena	Yes	
Response: Thank you for your support.		

4. The implementation plan compares the already approved requirements in the "TOP" standards with those that are proposed in TOP-001-2, TOP-002-2, and TOP-003-2. When comparing the already approved standards with those that are proposed, how would you assess the impact to reliability of the proposed standards are approved and the already approved standards are retired in accordance with the implementation plan?

Summary Consideration: Some commenters said that reliability would be improved, while the vast majority of the commenters said that the changes would either not affect or would improve reliability.

Two commenters indicated reliability would suffer. Of those two, one had a technical comment that was able to be addressed directly and which should be resolved. The other had no specific comments to support the contention that reliability would be reduced as a result of these changes.

The SDT made the following changes due to comments:

TOP-001-2, R6 - Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

Organization	Yes or No	Question 4 Comment
Joylyn Faust	There will be an adverse impact to reliability	See previous responses.
Response: Please see previous comment responses.		
Jason Shaver	There will be an adverse impact to reliability	Operational Planning Analysis: ATC is concerned with the use of the term Operational Planning Analysis in both TOP-001 and TOP-002. Once something is called an Operational Planning Analysis all associated requirements apply. Although the SDT is attempting to draw a distiction between contengency analysis which typically runs off and EMS and more traditiional PSS/E or power flow studies those requirements that talk about monitor or access to information apply equally. Example: If an entity chooses to uses a Eastern Interconnection base model to satisfy TOP-002 Requirement 1 that entity would have to also have to be in compliance with TOP-001 Requirement 13. Requirement 13 states that the TOP has to monitor or have access to information about condition and Facilities. By default a TOP would have to have access to information about every facility in the Eastern Interconnection model in order to be in compliance with calling

Organization	Yes or No	Question 4 Comment
		the study a Operational Planning Analysis and By using the same term to represent different study time frames causes a number of compliance issues with this standard. We suggest that the team either determines a single meaning for the term Operational Planning Analysis or clarifies the compliance obligations around the different time frames for Operational Planning Analysis.
Response: This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
MRO's NERC Standards Review Subcommittee	There will be no change to reliability	There seems to be a general lack of consistency in the use and meaning of terms relating to remote measurement and remote control of the BES in the TOP, COM and PRC standards. A better glossary would ensure consistent verbiage between the standards groups. The glossary term "Telemetering" is confusingly similar to the one for "SCADA". It wrongfully includes remote control as part of the definition. We suggest it be removed from the glossary and this project.
Response: The SDT agrees with your suggestion and has changed to "telemetry." The SDT cannot change other standards that are outside the scope of this project. The commenter may submit a SAR to correct this issue in every standard that has either term present. **TOP-001-2, R6 -** Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.		
Greg Rowland	There will be no change to reliability	These revised standards (including our proposed changes), provide more clarity and will improve compliance documentation, but we don't view that as a reliability improvement. Redline Posting for TOP-001-2 has a slight different definition than the Implementation Plan for Project 2007-03: Real-Time OperationsReliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency.Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.Duke prefers the first definition. It is the one based on the definition of "Emergency" since it doesn't mention "actual or expected".
Response: The SDT has updated the Reliability Directive definition in TOP-001-2 to match the definition in the Implementation Plan and the one originally developed by the RCSDT in Project 2006-06. **Reliability Directive** — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is		

Organization	Yes or No	Question 4 Comment
necessary to address an actual or expected Emergency.		
RoLynda Shumpert	Reliability will be improved	It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Response: A clerical error occurred in this posting that has been corrected.		
Dominion	Reliability will be improved	While the changes remove potential ambiguity from the reliability requirements, we believe that BAs, TOPs and RCs, in almost all circumstances, understand the roles they play to insure reliable grid operations. We believe these changes are predominately the result of an increased focus on compliance related activities (audit) and industry requests for clarity. We do agree that the change in R8 is an improvement as it will allow TOP and RC to focus on the limited set of SOLs that could have an adverse impact on the BES. Dominion would also like to make a general statement concerning the VSLs for all of these standards. We are unsure as to whether the correct threshold for Low, Moderate, High and Severe is correctly identified but have no basis for a denial or suggested change. We are curious as to how the various SDTs came up with these. In some draft standards, these thresholds seem to be developed around 25% quartiles, which makes it easier to accept the high and severe categories if you consider these equivalent to a pass/fail (D or F).
Response: Regarding the VSL percentages, the SDT applied these consistent with directions from FERC that indicated that the percentage bandwidths in each severity level of a VSL should be in 5% increments. No change made.		
Northeast Power Coordinating Council	There will be no change to reliability	No change to reliability assumes that the SOLs identified as a result of the Operational Planning Analysis by the Transmission Operator as supporting its local area reliability can ensure that all the existing SOLs that are being monitored and observed (for non-exceedance) by TOPs are identified through this process. Failure to identify any such SOLs will make the system vulnerable to unreliable operation.
FirstEnergy	There will be no change to reliability	We commend the hard work of the drafting team, but find it difficult to determine if these changes will affect the reliability of the BES.
Dan Rochester	There will be no change to	Our assessment that there should be no change to reliability is made on the assumption that the SOLs identified as a result of the Operational Planning Analysis by the Transmission Operator as supporting its local area reliability can ensure that all the existing SOLs that are being monitored and observed (for non-

Organization	Yes or No	Question 4 Comment
	reliability	exceedance) by TOPs are identified through this process. Failure to identify any such SOLs will expose the system to unreliable operation.
Jonathan Appelbaum	There will be no change to reliability	The team has rationalized the existing Standards and Requirements
Terry Harbour	There will be no change to reliability	Depending upon how SOLs are implemented and enforced there could be a negative impact to system reliability as transmission outages are further restricted reducing long-term maintenance to maximize short term risks to penalties.
E.ON U.S.	There will be no change to reliability	
Midwest ISO Standards Collaborators	There will be no change to reliability	
Bonneville Power Administration	There will be no change to reliability	
PJM	There will be no change to reliability	
IRC Standards Review Committee	There will be no change to	

Organization	Yes or No	Question 4 Comment
	reliability	
Western Electricity Coordinating Council	There will be no change to reliability	
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	There will be no change to reliability	
John Fish	There will be no change to reliability	
Kasia Mihalchuk	There will be no change to reliability	
Jon Kapitz	There will be no change to reliability	
Saurabh Saksena	There will be no change to reliability	
Catherine Koch	There will be no change to	

Organization	Yes or No	Question 4 Comment
	reliability	
Michael Gammon	There will be no change to reliability	
Response: Thank you for your comment.		
PacifiCorp	Reliability will be improved	The proposed standards will improve reliability because the new standards provide a much more clear and streamlined approach than in the already approved standards. This will also enable responsible entities to focus their time on compliance with standards that improve reliability rather than be concerned with compliance with poorly written or redundant standards.
SERC OC Standards Review Group	Reliability will be improved	“The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”
Southern Company Transmission	Reliability will be improved	Southern's comments none SERC's comments: Southern participated in developing these comments and support them Although we feel that reliability will be improved, we cannot determine whether the language that was inserted specifically in response to order 693 is not arbitrary, capricious or otherwise deleterious to reliability.
Darryl Curtis	Reliability will be improved	
Public Service Enterprise Group Companies	Reliability will be improved	
Michael Lombardi	Reliability will be improved	

Organization	Yes or No	Question 4 Comment
Leland McMillan	Reliability will be improved	
Richard Kafka	Reliability will be improved	
Response: Thank you for your support.		
Randi Woodward		Minnesota Power does not have any comments at this time.