

# Consideration of Comments

## Project 2014-03 Revisions to TOP and IRO Standards

The Project 2014-03 Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 35-day public comment period from December 3, 2014 through January 7, 2015. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 40 sets of comments, including comments from approximately 112 different people from approximately 78 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's [project page](#).

- [Made a grammatical correction to the rationale for Requirement R3 so that the second sentence now reads:](#) "... due to its lack of knowledge of the system involved."
- [Made a grammatical change to Measure M5](#) – "... issued by ~~the~~its Balancing Authority~~(s)~~ ...".
- [Made a grammatical change to Requirement R6](#) – "...issued by ~~that~~its Balancing Authority."
- [Made a grammatical change to the rationale for Requirement R7](#) – "This changess is in response ...".
- [Added the term 'generation' to Requirement R11 for consistency with the Functional Model](#) – "...maintain generation-Load-interchange balance ...".
- [Added clarifying language to the rationale for Requirement R13 - "The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available \(if used\). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation."](#)

[The SDT made clarifying changes for consistency to the VSLs for Requirements R6, R8, R11, R16, and R17 which can be found in the red-lined version of TOP-001-3.](#)

[The SDT also made several clarifying, non-substantive changes to the SOL Exceedance White Paper and the NOPR Issues document which can be found in the red-lined versions of those documents included with the next posting for this project.](#)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission,

you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at [valerie.agnew@nerc.net](mailto:valerie.agnew@nerc.net) . In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

- 1. Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes .....11**

---

<sup>1</sup> The appeals process is in the Standard Processes Manual: [http://www.nerc.com/comm/SC/Documents/Appendix\\_3A\\_StandardsProcessesManual.pdf](http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf)

**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
Additional Member		Additional Organization	Region	Segment Selection									
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10									
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3									
3.	Greg Campoli	New York Independent System Operator	NPCC	2									
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1									
5.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1									
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10									
7.	Kathleen Goodman	ISO - New England	NPCC	2									
8.	Michael Jones	National Grid	NPCC	1									
9.	Mark Kenny	Northeast Utilities		1									

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
10. Helen Lainis	Independent Electricity System Operator	NPCC 2												
11. Connie Lowe	Dominion Resources Services, Inc.	NPCC 5												
12. Alan MacNaughton	New Brunswick Power Corporation	NPCC 9												
13. Bruce Metruck	New York Power Authority	NPCC 6												
14. Silvia Parada Mitchell	NextEra Energy, LLC	NPCC 5												
15. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10												
16. Robert Pellegrini	The United Illuminating Company	NPCC 1												
17. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC 1												
18. David Ramkalawan	Ontario Power Generation, Inc.	NPCC 5												
19. Brian Robinson	Utility Services	NPCC 8												
20. Ayesha Sabouba	Hydro One Networks Inc.	NPCC 1												
21. Brian Shanahan	National Grid	NPCC 1												
22. Wayne Sipperly	New York Power Authority	NPCC 5												
2.	Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X	X					
<b>Additional Member</b>			<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Leo Staples	OG&E	SPP	5										
2.	Terri Pyle	OG&E	SPP	1										
3.	Don Hargrove	OG&E	SPP	3										
4.	Jerry Nottnagel	OG&E	SPP	6										
3.	Group	Connie Lowe	Dominion	X				X	X					
<b>Additional Member</b>			<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Randi Heise	NERC Compliance Policy	NPCC	5										
2.	Louis Slade	NERC Compliance Policy	RFC	5, 6										
3.	Larry Nash	Electric Transmission Compliance	SERC	1, 3, 5, 6										
4.	Group	Paul Haase	Seattle City Light	X		X	X	X	X					
<b>Additional Member</b>			<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>									
1.	Pawel Krupa	Seattle City Light	WECC	1										
2.	Dana Wheelock	Seattle City Light	WECC	3										
3.	Hao Li	Seattle City Light	WECC	4										
4.	Mike Haynes	Seattle City Light	WECC	5										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																	
			1	2	3	4	5	6	7	8	9	10								
5.	Dennis Sismaet	Seattle City Light	WECC	6																
5.	Group	Greg Campoli	ISO RTO Council Standards Review Committee (SRC)			X														
<b>Additional Member Additional Organization Region Segment Selection</b>																				
1.	Matt Goldberg	ISO-NE	NPCC	2																
2.	Ben Li	IESO	NPCC	2																
3.	Christina Bigelow	ERCOT	ERCOT	2																
4.	Charles Yeung	SPP	SPP	2																
5.	Terry Bilke	MISO	RFC	2																
6.	Ali Miremadi	CAISO	WECC	2																
6.	Group	Kelly Dash	Con Edison, Inc.		X		X		X	X										
<b>Additional Member Additional Organization Region Segment Selection</b>																				
1.	Edward Bedder	Orange and Rockland Utilities	NPCC	NA																
7.	Group	Michael Jones	National Grid		X		X													
<b>Additional Member Additional Organization Region Segment Selection</b>																				
1.	Brian Shanahan	National Grid (Niagara Mohawk Power Corporation)		NPCC	1, 3															
8.	Group	Michael Lowman	Duke Energy		X		X		X	X										
<b>Additional Member Additional Organization Region Segment Selection</b>																				
1.	Doug Hills			1																
2.	Lee Schuster			3																
3.	Dale Goodwine			5																
4.	Greg Cecil			6																
9.	Group	Kaleb Brimhall	Colorado Springs Utilities		X		X		X	X										
N/A																				
10.	Group	Robert Rhodes	SPP Standards Review Group			X														
<b>Additional Member Additional Organization Region Segment Selection</b>																				
1.	John Allen	City Utilities of Springfield	SPP	1, 4																
2.	Kevin Foflygen	City Utilities of Springfield	SPP	1, 4																
3.	Vinit Gupta	ITC Holdings	SPP	1																

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
4. Mike Kidwell	Empire District Electric	SPP	1, 3, 5											
5. Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5, 6											
6. Shannon Mickens	Southwest Power Pool	SPP	2											
7. James Nail	City of Independence, MO	SPP	3, 5											
8. Gary Slayton	Oklahoma Gas & Electric	SPP	1, 3, 5, 6											
9. Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4											
10. Sing Tay	Oklahoma Gas & Electric	SPP	1, 3, 5, 6											
11. J. Scott Williams	City Utilities of Springfield	SPP	1, 4											
11. Group	Andrea Jessup	Bonneville Power Administration		X		X		X	X					
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. John Anasis	Technical Operations	WECC	1											
2. Chris Higgins	Transmission Dispatch	WECC	1											
3. Fran Halpin	Duty Scheduling	WECC	1											
12. Group	Joe Depoorter	MRO- NERC Standards Review Forum												
<b>Additional Member Additional Organization Region Segment Selection</b>														
1. Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6											
2. Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6											
3. Chuck Lawrence	American Transmission Company	MRO	1											
4. Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5											
5. Dan Inman	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6											
6. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6											
7. Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6											
8. Jodi Jenson	Western Area Power Administration	MRO	1, 6											
9. Ken Goldsmith	Alliant Energy	MRO	4											
10. Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6											
11. Marie Knox	Midwest ISO Inc.	MRO	2											
12. Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6											
13. Randi Nyholm	Minnesota Power	MRO	1, 5											
14. Scott Nickels	Rochester Public Utilities	MRO	4											
15. Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6											
16. Tom Breene	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6											

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
			1	2	3	4	5	6	7	8	9	10		
17. Tony Eddleman	Nebraska Public Power District	1, 3, 5												
13. Group	Ben Engelby	ACES Standards Collaborators							X					
	<b>Additional Member</b>	<b>Additional Organization</b>	<b>Region</b>	<b>Segment Selection</b>										
1.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5										
2.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6										
3.	Ginger Mercier	Prairie Power, Inc.	SERC	3										
4.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1										
5.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1										
6.	Lucia Beal	Southern Maryland Electric Cooperative	RFC	3										
7.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5										
8.	John Shaver	Arizona Electric Power Cooperative/ Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5										
9.	Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	3, 5										
14. Group	Sandra Shaffer	PacifiCorp							X					
N/A														
15. Individual	Daniel Duff	Liberty Electric Power LLC						X						
16. Individual	Thomas Foltz	American Electric Power		X		X		X	X					
17. Individual	Chris Scanlon	Exelon		X		X		X	X					
18. Individual	Denise M. Lietz	Puget Sound Energy		X		X		X						
19. Individual	Joshua Smith	Oncor Electric Delivery LLC		X										
20. Individual	Scott Bos	Corn Belt Power Cooperative		X		X								
21. Individual	David Jendras	Ameren		X		X		X	X					
22. Individual	Catherine Wesley	PJM Interconnection			X									
23. Individual	Scott Berry	Indiana Municipal Power Agency				X								
24. Individual	John Brockhan	CenterPoint Energy Houston Electric LLC		X										
25. Individual	Brett Holland	Kansas City Power and Light		X		X		X	X					
26. Individual	Gerald Farringer	Consumers Energy Company				X	X	X						
27. Individual	Russ Schneider	Flathead Electric Cooperative				X	X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
28.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC	X		X								
29.	Individual	Donald E Nelson	Massachusetts Department of Public Utilities										X	
30.	Individual	Erika Doot	US Bureau of Reclamation	X				X						
31.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration, LP					X						
32.	Individual	Leonard Kula	Independent Electricity System Operator		X									
33.	Individual	Andrew Z. Puztai	American Transmission Company, LLC	X										
34.	Individual	Jason Snodgrass	Georgia Transmission Corp	X										
35.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X					
36.	Individual	Anthony Jablonski	ReliabilityFirst											X
37.	Individual	Texas Reliability Entity, Inc.	Texas Reliability Entity, Inc.											X
38.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X									
39.	Individual	Russell A. Noble	Cowlitz PUD			X	X	X						



If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

**Summary Consideration:** The SDT thanks the commenters for following the guidelines and will consider your supporting positions as part of its deliberations.

Organization	Agree	Supporting Comments of "Entity Name"
Exelon	Agree	<p>Exelon will cast an Affirmative vote but agrees that the SDT should consider the comments filed by Duke Energy regarding: R1 be focused on the TOP issuing Operating Instructions and suggests the following revision to R1 for clarity: "Each Transmission Operator shall issue Operating Instructions, as necessary, to maintain the reliability of its Transmission Operator Area".</p> <p>R2 be focused on the BA issuing Operating Instructions and suggests the following revision to R2 for clarity: "Each Balancing Authority shall issue Operating Instructions, as necessary, to maintain the reliability of its Balancing Authority Area".</p>
Corn Belt Power Cooperative	Agree	Support the comments submitted by the MRO NERC Standards Review Forum
Kansas City Power and Light	Agree	SPP - Robert Rhodes
Massachusetts Department of Public Utilities	Agree	NPCC

Organization	Agree	Supporting Comments of "Entity Name"
Lincoln Electric System	Agree	MRO NERC Standards Review Forum (NSRF)
Seattle City Light		NPCC
PacifiCorp		Berkshire Hathaway

1. Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes

**Summary Consideration:** The SDT has considered all of the comments submitted and has made the following clarifying, non-substantive changes due to industry comments

**Rationale for Requirement R3:** Added 'to' the second sentence to correct the grammar in the sentence. The sentence now reads: "...due to its lack of knowledge of the system involved."

**M5.** Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by ~~the~~its Balancing Authority~~(s)~~ unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. 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 in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

**R6.** Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by ~~that~~its Balancing Authority.

**Rationale for Requirement R7:** ~~This changes~~ is in response to the Independent Experts Review Panel (IERP) recommendations.

**R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order ~~to~~ maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

**Rationale for Requirement R13:** added – The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

The SDT made clarifying, non-substantive changes for consistency to the VSLs for Requirements R6, R8, R11, R16, and R17 which can be found in the red-lined version of TOP-001-3.

The SDT also made several clarifying, non-substantive changes to the SOL Exceedance White Paper and the NOPR Issues document which can be found in the red-lined versions of those documents included with the next posting for this project.

Organization	Yes or No	Question 1 Comment
<p>Northeast Power Coordinating Council</p>	<p>No</p>	<p>Regarding Requirement R13, there is concern that an operator will be obligated to perform the assessment. Given that the Rationale for Requirement R13, although not auditable, supports the Requirement’s wording, suggest revising the Rationale Box to read: The new requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator’s Operating Plan may describe how to perform the Real-time Assessment. It would also be helpful to confirm that at times no actions may be required if system conditions have not changed within the thirty minute window and that previous contingency analysis or assessments may be used to perform the Real time Assessment for subsequent hours.</p> <p>A suggested revision to Requirement R13:R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes, or in the timeframe specified in an Operating Plan when the Transmission Operator operates in a known state and is unable to perform the Real-time Assessment every 30 minutes.</p> <p>And for Measure M13:M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment was performed at least once every 30 minutes, or in the timeframe specified in an Operating Plan when the Transmission Operator operates in a known state and is unable to perform the Real-time Assessment every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.</p>

Organization	Yes or No	Question 1 Comment
		Appropriate wording consistent with this should be added to Section F. Associated Documents.
<p><b>Response:</b> The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity’s obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:</p> <ol style="list-style-type: none"> <li>30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.</li> <li>Previous SDT comment responses have made clear that it doesn’t expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where normal methods aren’t operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn’t be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.</li> </ol>		

Organization	Yes or No	Question 1 Comment
		<p>3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is restarted for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue.</p> <p>No change made.</p> <p>The SDT believes that with the additions made for clarification to the rationale for the requirement that no changes are required to the requirement wording. No change made.</p> <p>Since no changes were made to the requirement, no changes are required to the measure. No change made.</p> <p>The SDT believes that sufficient clarification has been provided in the rationale for the requirement and that no changes are required in Section F. No change made.</p>
Seattle City Light	No	<p>Seattle City Light (SCL) appreciates the efforts made by the Standard Drafting Team to respond to comments from industry and create a quality Standard that is clear and complete. Considerable progress has been made from earlier postings. Some areas remain for improvement.</p> <p>Specifically, SCL disagrees with the R13 requirement for ensuring a real time assessment each 30 minutes, and believes a two-hour requirement to be sufficient and consistent with EOP-008. If 2 hours is too long, SCL urges consideration of a 60 minute requirement, as recommended in an earlier posting. A 30 minutes requirement in our opinion does not add enough reliability benefit to be worth the additional cost, effort, and compliance risk.</p>

Organization	Yes or No	Question 1 Comment
		<p>SCL also continues to recommend that R19 and R20 be deleted from TOP-001-3, as discussed previously.</p> <p>Finally, SCL is concerned with the growing number of BA-specific requirements (R11, R17, and R20) included a TOP-area Standard. While we understand the difficulty of aligning all requirements within the appropriate Standard area (BAL, TOP, etc.), we urge extra effort be made to maintain and promote such alignment more than has been done to date. For example, INT-009-2 included BA requirements that do not properly belong in that Standard but were included out of expedience and a lack of willingness to develop an appropriate new SAR. SCL recommends reconsidering the need to include BA-only requirements within a TOP-family Standard, and alternative approaches to addressing these reliability needs in a different Standard.</p>
<p><b>Response:</b> The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity’s obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:</p> <ol style="list-style-type: none"> <li>30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.</li> <li>Previous SDT comment responses have made clear that it doesn’t expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where</li> </ol>		

Organization	Yes or No	Question 1 Comment
		<p>normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.</p> <p>3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is restarted for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue.</p> <p>No change made.</p> <p>As has been previously stated by the SDT, Requirements R19 and R20 serve to complete the loop on data exchange. Proposed TOP-003-3 sets out the requirements for the data itself but there needs to be corresponding requirements concerning the hardware and systems that allow for the data exchange to actually take place. The Commission has made it clear in past Orders that one can't assume that systems are in place when writing requirements for specific actions. In this case, that would mean that one can't assume that hardware or systems are in place to allow for data exchange simply because requirements exist that describe what data needs to be exchanged. No change made.</p> <p>As a general concept, the SDT agrees that requirements pertinent to Balancing Authorities should reside in standards specific to Balancing Authorities. However, the existing, approved TOP standards already had several requirements applicable to Balancing Authorities and the SDT is obligated to maintain those requirements so as not to introduce a reliability gap. The scope of the SAR for</p>



Organization	Yes or No	Question 1 Comment
<p>Project 2014-03 did not allow for the SDT to revise the BAL standards where these requirements would most likely be placed so the SDT was obligated to retain the requirements within the TOP standards. The SDT did discuss this issue with NERC management and obtained an assurance that an overarching project to address the issue would be instituted in the future. No change made.</p>		
<p>ISO RTO Council Standards Review Committee (SRC)</p>	<p>No</p>	<p>Requirement R11, as proposed, states, “Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.” The SRC suggests that Requirement R11 is duplicative of requirements and obligations placed on Balancing Authorities in the BAL Standards and, therefore, suggests deletion of Requirement R11.</p>
<p><b>Response:</b> The SDT has investigated the BAL standards and believes that an explicit requirement for monitoring by the Balancing Authority is necessary. There are no specific requirements in BAL standards for the Balancing Authority to monitor. And the Commission has made it clear in previous Orders that one can’t assume something based on other requirements that dictate certain actions. In this case, just because an entity has to adhere to requirements for AGC or DCS and that it can’t do that without monitoring is not sufficient cause to not have a specific monitoring requirement. No change made.</p>		
<p>Con Edison, Inc. National Grid</p>	<p>No</p>	<p>Requirement R13 is problematic. The 30 minute requirement in R13 is too restrictive and inconsistent with EOP-008, which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be granted the same time consideration to restore real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13:</p> <ul style="list-style-type: none"> <li>o Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every two hours.</li> <li>o Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every 30 minutes when the EMS &amp; SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform real-time assessments within two hours.</li> </ul>

Organization	Yes or No	Question 1 Comment
Cowlitz PUD	No	<p>Cowlitz submits negative votes due to the SDT responses surrounding Real-Time Assessment (RTA) being performed at least every 30 minutes, and is concerned comment submitted by the stakeholders have not been adequately addressed. Cowlitz disagrees with the SDT responses which imply a full quality RTA can be performed in all circumstances. Comment submitted by Northeast Power Coordinating Council addressed a concern over the inability to perform RTAs during an EOP-008-1 primary to backup control center transition, and that responsible entities should be allowed a 2-hour window in which to reestablish a 30-minute RTA schedule. The SDT response stipulates that EOP-008-1 supports continuance of 30-minute RTAs during the transition. While Cowlitz agrees that the 30-minute RTA must continue, it will be limited to the available data from which to complete the assessment. Although EOP-008-1 allows for a 2-hour transition plan, it does not imply a 2-hour suspension of registered functional obligation is allowed; however, it does not require all systems to be maintained operational during the transition. The objective is to “ensure continued reliable operations of the Bulk Electric System” during an emergency; this of course is contingent upon circumstances not exceeding reasonable expectations of an entity’s ability to respond to emergency situations. The objective is to have a planned response to a contingency - loss of a control center - that will restore critical control and awareness tools necessary for continued functional obligations, not a guaranteed continuance of all the control and awareness tools. Cowlitz respectfully requests the SDT to clarify that the RTA must continue subject to the data available, and remove any misunderstanding concerning the derivation of the RTA when BES awareness has been compromised beyond the reach of the Reliability Standards.</p>
<p><b>Response:</b> The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable,</p>		

Organization	Yes or No	Question 1 Comment
		<p>and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity’s obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:</p> <ol style="list-style-type: none"> <li>1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.</li> <li>2. Previous SDT comment responses have made clear that it doesn’t expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where normal methods aren’t operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn’t be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.</li> <li>3. There are additional elements to the timing question that need to be considered as well. The requirement doesn’t mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is restarted for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the</li> </ol>

Organization	Yes or No	Question 1 Comment
		<p>29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue.</p> <p>No change made.</p>
<p>Duke Energy</p>	<p>No</p>	<p>R1&amp;R2: Duke Energy still has concerns regarding the wording associated with R1 and R2. The SDT stated in their consideration of Duke Energy comments that, “Specific actions for specific situations will be covered under the applicable standards.” Our fear is that the language opcan still be viewed as a failure to act or a failure to maintain. Duke Energy understands and agrees, through informal discussions with the SDT that the intent of R1 and R2 is that the BA and TOP must take some action in order to maintain the reliability of the BES and not whether the BA or TOP succeeded in said action.</p> <p>R9: Duke Energy agrees with the removal of “sustained” and the addition of a timing requirement for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. However, would like the SDT to provide a response to the following question, If the primary channel (RTU, etc.) is out of service and the backup is working properly, then is the expectation for the BA and TOP to notify the RC and other entities affected that the primary communication channel is out service? (Even though monitoring, assessment capabilities, etc. have not been affected). Duke Energy understands and agrees, through informal discussions with the SDT, that if back-up communication channels from the BA and TOP are still providing data then there is no need for communications to the RC and others affected as described in R9.</p> <p>Associated Documents (SOL Exceedance document): Duke Energy requests clarification on the compliance ramifications of the Associated Documents</p>

Organization	Yes or No	Question 1 Comment
		<p>section. Upon our review of Appendix 3A of the NERC Rules of Procedure, Associated Documents are not included in the Appendix, and thus an entity would not consider the section to be an enforceable part of the standard for compliance purposes. We do not feel that including a URL, rather than attaching the entire document to the standard clears up any confusion the industry may have on this issue. Duke Energy maintains that this document could be viewed as an expansion of what is currently considered to be an SOL, and feels that this document should be viewed as purely a Guideline/Technical Basis document as is currently labeled in other NERC standards (see CIP-004-7).</p>
<p><b>Response:</b> The SDT agrees with the stated intent of the requirements offered by the commenter, specifically the intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and having agreed sees no reason to revise the current wording. No change made.</p> <p>The SDT agrees with the interpretation provided by the commenter, specifically that if back-up communication channels from the Balancing Authority and Transmission Operator are still providing data then there is no need for communications to the Reliability Coordinator and others affected as described in Requirement R9. Such an interpretation is consistent with similar requirements on notification of facility outages in other standards. No change made.</p> <p>The SDT agrees that the SOL Exceedance White Paper is a guideline technical document providing clarification on how to determine an SOL and what needs to be done upon determining an SOL. For clarification, the SDT has revised the wording with reference to the White Paper in Section F. See redlined version for exact text.</p>		
Colorado Springs Utilities	No	<p>Thank you standard drafting teammates for all of your work on this complex standard!</p> <p>R13 Comment: R13 requires that a Real-time Assessment is performed at least once every 30 minutes. We believe that this is in conflict with EOP-008 which allows for a two hour transition period to back-up control center. How does the standard drafting team anticipate that an entity that is failing</p>

Organization	Yes or No	Question 1 Comment
		<p>over to a back-up control center is to maintain compliance with this requirement? This requirement needs to be modified to make sure it is consistent with EOP-008.</p> <p>General Comment: We re-submit our comment concerning the use of the word “maintain” which has much the same implications as “ensure”. We concur that entities must act timely and prudently for the reliability of the BES, but entities should not be unduly held accountable for system conditions outside their control that lead to reliability issues of the BES. We favor the word “address” and “address reliability” to “maintain” and “maintain reliability.” The fact that a reliability issue or even a black-out has occurred is not sufficient to prove that entities were not appropriately acting. We must avoid requirement language that attaches liability just because a reliability event occurs.</p>
<p><b>Response:</b> The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity’s obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:</p> <ol style="list-style-type: none"> <li>30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.</li> <li>Previous SDT comment responses have made clear that it doesn’t expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where</li> </ol>		

Organization	Yes or No	Question 1 Comment
		<p>normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.</p> <p>3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is restarted for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue.</p> <p>No change made.</p> <p>The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and sees no reason to revise the current wording. The SDT moved from 'ensure' to 'maintain' at the express request of numerous entities in previous postings. The SDT agrees that simply because bad things happened it does not mean that an entity did not do its duty or necessarily acted improperly. No change made.</p>
<p>SPP Standards Review Group Oklahoma Gas &amp; Electric</p>	<p>No</p>	<p>TOP-001-3R1 &amp; R2 - We take exception to the step back which the SDT has taken with the change of 'address' to 'maintain' in Requirements R1 and R2. The SDT mentioned that one of the reasons for this change was to eliminate</p>

Organization	Yes or No	Question 1 Comment
		<p>the threat of double jeopardy. We don't see that happening with the terminology being proposed.</p> <p>Rationale Box for R3 - In the Rationale Box for Requirement R3, insert a 'to' between 'due' and 'its' in the last line.</p> <p>R5 - Change 'Balancing Authority' to 'Balancing Authority(s)' in the second line of Requirement R5 to make the requirement consistent with the measure.</p> <p>R6 - Change 'that' in the 3rd line to 'its' for consistency with Requirement R4.</p> <p>Rationale Box for R7 - In the Rationale Box for Requirement R7, delete the apostrophe in front of 'This' at the start of the 2nd sentence and also change 'changes' to 'change' in the same sentence.</p> <p>R9 - If the SDT's intent was for the 30-minute threshold to apply to both planned and unplanned outages, then the commas surrounding the phrase 'and unplanned outages of 30 minutes or more' need to be deleted. As written, the 30-minute threshold only applies to unplanned outages. If this wasn't the SDT's intent, it should be. Additionally, the current wording obligates the Balancing Authority and Transmission Operator to notify its Reliability Coordinator whenever an RTU goes down. We should focus on outages of equipment which have an impact on the reliability of the Interconnection. Therefore, we recommend the following language: 'Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned and unplanned outages of 30 minutes or more for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities, which adversely impact the reliability of the Interconnection.'</p>



Organization	Yes or No	Question 1 Comment
		<p>R10 - We have concerns about the elimination of the caveat regarding identification of facilities by the Transmission Operator for inclusion in the determination of SOL exceedances. Leaning on the 'as necessary' in Requirement R10 is too much of a stretch. We suggest the SDT re-insert the 'identified by the Transmission Operator' in R10 as follows: 'Each Transmission Operator shall perform the following as necessary, when identified by the Transmission Operator, for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:'</p> <p>Change 'voltages' in Requirement 10, Part 10.2 to 'voltage'. Make the same change in the Measure.</p> <p>R11 - Change 'Load-interchange balance' to 'generation-Load-interchange balance' which is consistent with the definition of Balancing Authority as contained in the Functional Model. That definition also includes a component for contributing to Interconnection frequency which the SDT has already incorporated in Requirement R11.</p> <p>VSLs for R8 - If the SDT has not changed its position on the inclusion of 'other' in this requirement, usage by the way which is consistent with that in Requirement R7, then 'other' needs to be deleted from the Lower, Moderate and High VSLs for Requirement R8.</p> <p>VSLs for R16 and R17 - Measures 16 and 17 have been inserted in the Severe VSLs for Requirements 16 and 17, respectively. They should be deleted.</p> <p>We recommend that all changes we have proposed for the standards be reflected in the VSLs and RSAW as well.</p> <p>Implementation Plan Split the 2nd paragraph on the 4th page into two sentences. Do this by replacing '...SW Outage Report, and this implementation plan...' with '...SW Outage Report. This implementation</p>

Organization	Yes or No	Question 1 Comment
		<p>plan...' at the end of the 3rd and the beginning of the 4th lines of the paragraph.</p> <p>In the paragraph under General Considerations on page 4, delete the 's' on 'Requirements R5' at the end of the 3rd line.</p> <p>In the 1st paragraph under Implementation Plan for Definitions on page 8, replace 'definitions' in the 4th line with 'definition.'</p> <p>SOL Whitepaper The '3.' at the top of page 3 should be '4.'</p> <p>Split the 1st sentence of the paragraph immediately following '4.' above into two sentences by making the following change in the 3rd line of that paragraph. Replace '...Requirement R2 sub-requirements, the assumption being that...' with '...Requirement R2 sub-requirements. The assumption being that...'</p> <p>In the last line under the first 3 on page 4, change 'limit' to 'limits'.</p> <p>Replace 'Owner' at the top of page 6 with 'Owner's'.</p> <p>Capitalize 'process' at the end of the last line of the Operating Process definition on page 10.</p> <p>NOPR Issues The language quoted on page 2 for IRO-008-2, Requirement R2 is not consistent with the language posted in the final ballot package of October 10, 2014.</p> <p>The language quoted on page 2 for IRO-008-2, Requirement R4 is not consistent with the language posted in the final ballot package of October 10, 2014.</p> <p>The language quoted on page 3 for IRO-002-4, Requirement R2 is not consistent with the language posted in the final ballot package of October 10, 2014.</p>

Organization	Yes or No	Question 1 Comment
		<p>The language quoted on page 7 for TOP-001-3, Requirement R11 is not consistent with the language currently posted for comment and ballot.</p> <p>The language quoted on page 7 for TOP-001-3, Requirement R13 is not consistent with the language currently posted for comment and ballot. The language shown is actually Requirement R11 of the posted version.</p> <p>The reference to proposed IRO-014-2, Requirement R1 on page 20 should actually be to IRO-014-3.</p> <p>Part 1.1 of IRO-017-1, Requirement R1 shown on page 20 is missing the 1.1 designation.</p> <p>The language quoted on page 21 for TOP-003-3, Requirement R5, Part 5.3 is not consistent with the language posted in the final ballot package of October 10, 2014.</p> <p>The language quoted on page 21 for IRO-010-2, Requirement R3, Part 3.3 is not consistent with the language posted in the final ballot package of October 10, 2014.</p>
<p><b>Response:</b> R1 - The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and having agreed sees no reason to revise the current wording. No change made.</p> <p>R3 - The SDT agrees and has made the suggested non-substantive clarifying change. See summary consideration for actual wording.</p> <p>R5 - The SDT agrees that there is an inconsistency but believes the proper fix is to adjust the measure to be consistent with the requirement. The SDT has made the suggested non-substantive clarifying change. See summary consideration for actual wording.</p> <p>R6 - The SDT agrees and has made the suggested non-substantive clarifying change. See summary consideration for actual wording.</p> <p>R7 - The SDT agrees and has made the non-substantive semantic change as suggested. See summary consideration for actual wording.</p> <p>R9 - The 30-minute threshold only applies to unplanned outages. All impactful planned outages require notification. However, the SDT does not agree that such verbal notifications necessarily go down to the RTU level. The SDT believes that ICCP quality code</p>		

Organization	Yes or No	Question 1 Comment
		<p>information is an acceptable form of communication and is included within the measure as “electronic communication”. Additionally, reporting requirements can also be covered as part of Operating Plans between the Transmission Operator and Reliability Coordinator. The intent of the standard is not to be administrative in nature. Allowing entities to determine what is significant would lead to an inconsistent application of the requirement. No change made.</p> <p>R10 – The SDT believes the current wording is correct and finds the suggested re-insertion redundant. No change made.</p> <p>R10.2 – The SDT believes the current wording is correct and believes the use of the plural term is correct in this context. No change made.</p> <p>R11 – The SDT agrees that the suggested change is in keeping with the language in the Functional Model which is what the SDT was trying to do. The SDT has made the non-substantive change. See summary consideration for actual wording. Corresponding changes were made to the measure and VSLs.</p> <p>VSL for R8 – The SDT has not changed its position with regard to the use of ‘other’ and has deleted the term from the VSLs as suggested. See red-lined standard for change.</p> <p>VSLs for R16/R17 – The SDT agrees and has made the suggested change. See red-lined standard for change.</p> <p>The SDT has updated the VSL language as needed. The SDT does not have the authority to update RSAW language but it will pass on the needed changes to NERC Compliance.</p> <p>The Implementation Plan for Project 2014-03 has already been adopted by the Board and the SDT is unable to make semantic changes to the document at this time. The document was posted with proposed TOP-001-3 solely for convenience of reference. No change made.</p> <p>SOL Exceedance White Paper – The SDT agrees and has changed the numeric value to 4. See red-lined White Paper for change.</p> <p>The SDT believes that splitting the sentences would slightly change the intent of the paragraph without adding any additional clarity. No change made.</p> <p>The SDT agrees and has made the suggested change. See the red-lined White Paper for change.</p> <p>The SDT agrees and has made the suggested change. See the red-lined White Paper for change.</p> <p>The SDT agrees and has made the suggested change. See the red-lined White Paper for change.</p>

Organization	Yes or No	Question 1 Comment
<p>NOPR Issues: The SDT agrees on the discrepancy for proposed IRO-00-8-2, Requirement R2 and has corrected this problem in the document. Proposed IRO-008-2, Requirement R4 should not have been listed as a pertinent requirement. The text prior to the list of pertinent requirements was corrected to show the correct list of requirements. The proper reference on page 3 is to proposed IRO-002-4, Requirement R3. The text for proposed TOP-001-3, Requirement R11 has been updated on page 7. The text for proposed TOP-001-3, Requirement R13 has been updated on page 7. The reference to proposed IRO-014-3 on page 20 has been corrected. The 1.1 designation has been added to proposed IRO-017-1 on page 20. The text of proposed TOP-003-3, Requirement R5, Part 5.3 and IRO-010-2, Requirement R5, Part 5.3 has been updated on page 21.</p>		
<p>Bonneville Power Administration</p>	<p>No</p>	<p>BPA’s primary concern is with the way Requirement R8 is written. It requires BPA to inform the RC and any impacted TOP’s and BA’s of an actual or expected operating condition that results in or could result in an Emergency. Emergency is defined in the NERC Glossary as: “Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System” BPA could interpret this to mean that our dispatchers should call the RC anytime any 115kV line anywhere on BPA’s system is threatened by fire, wind, ice, or other conditions. BPA is also concerned about having to inform these other parties of “expected operating conditions ...that could result in an Emergency.” It is not clear to BPA how an auditor will interpret this. BPA is concerned that, given how broad the definition of “Emergency” is, we might violate R8 for not anticipating a particular operating condition or its full consequences. Again, “Emergency” does not merely refer to a WECC-wide stability event like September 8. This is written such that it includes a simple trip of a 115kV line.</p>
<p><b>Response:</b> The SDT believes that the requirement is written correctly and captures the intent of the SDT in this matter. Other entities need to know what is happening in other areas that will impact the reliability of the BES in order to properly manage its own systems. If the loss of a 115 kV line impacts BES reliability, the outage needs to be shared with other entities. Using ‘Emergency’ as a qualifier for these notifications provides a limit to the number of notifications that will be required. No change made.</p>		

Organization	Yes or No	Question 1 Comment
MRO- NERC Standards Review Forum	No	<p>: The NSRF cannot support R1 and R2 as written within the proposed TOP-001-3. The NSRF believes that as written, these Requirements are a catch all, ambiguous, and not measurable. FERC Order 693, section 253 states, "...compliance will in all cases be measured by determining whether the party met or failed to meet the Requirement..." The NSRF does not understand what is being required by the TOP and BA, respectfully. Granted, the SDT wants a TOP and BA to "maintain the reliability of its Area via its own actions or by issuing Operating Instructions". The NSRF views this as what a TOP and BA should be doing at all times. But in order for a TOP or BA to show proof of compliance, the industry needs to know what is required of them? The SDT has not provided any relief to the TOP and BA as we move into risk based compliance activities. The NSRF has referred to the Standards Process Manual to point out to the SDT that Standards Process Manual section 2.4 describes a "Results Based Requirement" as "Each requirement of a reliability standard shall identify what Functional Entities shall do, and under what conditions, to achieve a specific reliability objective and not how that objective is achieved". In FERC's Order regarding NERC's Five-Year Performance Assessment [149 FERC ¶ 61,141, P 70 (2014)], the Commission recently highlighted the importance of improving consistency: "The Commission recognizes and supports NERC's efforts to increase consistency and promote coordination across the ERO Enterprise. A key element of consistency is the transparency of the ERO Enterprise's processes and its outcomes. Improved consistency and coordination helps to clarify the roles and responsibilities of NERC and the Regional Entities and should lead to more efficient and uniform work practices. Specifically, we believe that a focus on achieving consistent compliance and enforcement outcomes (e.g., monetary penalties, registration decisions, and consistent understanding of Reliability Standard requirements) while not equating consistency with a "lowest common denominator" approach would provide the greatest benefit to registered</p>

Organization	Yes or No	Question 1 Comment
		<p>entities.” As written, R1 and R2 do not provide a “consistent understanding of Reliability Standard requirements”. The NSRF has even given proposed rewrite of “A possible rewrite of R1 and R2 to read: “Each (BA, TOP) shall issue Operating Instructions to address the reliability of its area when direct actions require more assistance “. The SDT replied that “The SDT does not believe that Requirements R1 and R2 are problematic. The requirement simply states that an entity maintain the reliability of its area by the means it has at its disposal either through its own actions or by issuing Operating Instructions. If the entity does that, then the SDT believes it has met the spirit and intent of the requirement”. The NSRF does not agree with the “spirit” that the SDT believes is the intent of the Requirements. If the SDT believes that the “TOP and BA shall maintain the reliability of its area by the means it has at its disposal”, then that should be clearly stated within R1 and R2. The NSRF believes that section 253 of FERC Order 693 could then be adhered, too.</p> <p>The NSRF recommends that the SDT consider removing the following language from the proposed “Real-time Assessment” definition: “known Protection System and Special Protection System status or degradation,” The revised definition would be as follows: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)Reason for removal of the language: This language should be removed because it is unrealistic for entities to perform a new real-time assessment every 30 minutes that incorporates the necessary contingency definition changes driven by a Protection System failures. EMS systems using real-time contingency</p>

Organization	Yes or No	Question 1 Comment
		<p>analysis tools do not include contingency definitions for the myriads of potential tripping scenarios for various failed protection systems. Therefore, off-line analysis would need to be performed by the system operator or another employee. Because off-line analysis would need to be used, it is an unreasonable burden to have to perform this assessment every 30 minutes as would be required by the proposed Requirement R13. What happens when the analysis cannot be accomplished within 30 minutes due to other emergency conditions? Whereby the Entity is reacting to a priority situation?</p> <p>With regard to R13, we believe the SDT has improved the language by revisions such that the TOP shall “ensure that a Real-time Assessment is performed at least once every 30 minutes;” however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, we would recommend the following language: R13: “Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP.” Measure M13 would need commensurate edits to conform to this R13 language. Entities have made these comments before and the SDT did not agree as they said; The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn’t about maintaining RTCA or any other specific tool, it’s about maintaining situational awareness at all times. No change made. The first concern is the NSRF believes that without further clarification, System Operators will not have the “situational awareness” because they will not know “known</p>



Organization	Yes or No	Question 1 Comment
		<p>Protection System and Special Protection System status or degradation...” per the Real-time Assessment definition, thus will most likely be non-compliant on a daily basis. A 4000 breaker Transmission system can have up to 20,000 (4000 x 5 parts of a Protection System) parts that would need to be tracked every 30 minutes. This is unrealistic and not physically possible. The SDT continues to use the words “have situational awareness” in their response to comments, and that the Requirement is not about an RTCA. But without using the RTCA, how will the System Operator prevent instability, uncontrolled separation or Cascading outages, per the Purpose of this proposed Standard? The Real-time assessment must consist of existing and potential operating conditions, per the definition. A System Operator cannot calculate all the minimum inputs every 30 minutes without using some type of calculating device. The NSRF would also wish to point out that the SDT may believe that an Entity’s RTCA may run every several minutes and thus fulfilling the 30 minute requirement. An Entity cannot be directed to have an RTCA and most RTCA systems, do not function properly if all the data points are not provided, i.e., transmission lines out of service due to severe weather, thus unable to provide the required “situational awareness”.</p>

**Response:** The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and having agreed sees no reason to revise the current wording. No change made.

The definition of Real-time Assessment has already been approved by industry and adopted by the Board. It was included with proposed TOP-001-3 for ease of reference and is not subject to change at this time.

The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity’s obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to

Organization	Yes or No	Question 1 Comment
		<p>the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:</p> <ol style="list-style-type: none"> <li>1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.</li> <li>2. Previous SDT comment responses have made clear that it doesn't expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.</li> <li>3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is restarted for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue.</li> </ol>

Organization	Yes or No	Question 1 Comment
No change made.		
ACES Standards Collaborators	No	<p>(1) Requirements R1 and R2 are vague, overly broad, and duplicative of other requirements and will be difficult to demonstrate compliance with and as a result may distract System Operators from their reliability mission. If there is a disturbance on the transmission system, there could be a potential violation of R1 and R2 because the TOP/BA did not “maintain reliability” of its area regardless whether its actions were appropriate or not. This requirement is very subjective and will allow auditors or investigators to interpret a system operator’s actions after-the-fact to determine if they acted appropriately. There is nothing in these requirements that allow for a reasonable measure of performance. The Compliance Enforcement Authority will evaluate whether actions were taken, Operating Instructions were issued, and whether or not reliability was maintained. There could be a violation whenever a disturbance occurs in the TOP/BA area including events beyond their control such as tornadoes or hurricanes, as reliability was not maintained. These requirements are duplicative with many other requirements. For example, failing to initiate an Operating Plan to mitigate an SOL exceedance in R14 is failing to take action or issue Operating Instructions to maintain reliability. While the RSAW’s do attempt to limit the burden of proving compliance with every Operating Instruction by instructing auditors to monitor compliance during events, RSAWs are simply guidance documents that an auditor is not obligated to follow. Thus, a TOP and BA must be able to prove compliance by retaining every Operating Instruction and that it acted in response to every operating threat. This is a tall order that will distract System Operators from their reliability mission and as a result be a detriment to reliability. While System Operators are already tasked with logging actions and information throughout the day, their standards for documenting information likely are not at a level that would be auditably compliant. Thus, System Operators will have to focus time and energy that should be focused on Operating the</p>

Organization	Yes or No	Question 1 Comment
		<p>system with writing auditably compliant logs. A better solution would be to revert these requirements back to the authority requirements of the existing standards. The data retention section of this standard exacerbates the issue by requiring evidence that is not an operator log or voice recording to be retained for up to two calendar years. What other evidence does the drafting team foresee will be used to demonstrate compliance? These requirements need to be revised to include a reasonable measure of performance and the VSL table should be modified to account for instances where contributing factors led to reliability not being maintained.</p> <p>(2) Requirements R1 and R2 do not line up with the functional model. A TOP is obligated per R1 “to act to maintain the reliability of its Transmission Operator Areas via its own actions or by issuing Operating Instructions.” This means that a TOP must respond to all reliability threats including those that are not its responsibility. Consider a large generating plant trips and frequency declines significantly but there are not SOL or IROL violations or voltage violations. In other words, the transmission system is within operating limits with the exception of frequency. The TOP should not act because the BA should be acting to recover frequency. In fact, if the TOP does act, it likely will be detrimental to reliability. However, the TOP would be in technical violation of the requirement because it did not act and or issue Operating Instructions in response to a reliability threat within its Transmission Operator Area.</p> <p>(3) Requirements R3, R4, R5, and R6 should be modified in several ways. First, we disagree with the classifications of High VRF and Severe VSL for failing to comply with an Operating Instruction in all instances. Failing to follow an Operating Instruction during routine operations, is unlikely “to directly cause or contribute to Bulk-Power System instability, separation or a cascading sequence of failures” as required by a High VRF. As an example, the failure to implement the Operating Instruction correctly in the Arizona-Southern California did not directly cause the outage as it was not a root</p>

Organization	Yes or No	Question 1 Comment
		<p>cause. Rather it was the initiating action and other standards violations were required to cause the blackout. The VRF should be reduced to Medium. Second, the VSL table should be graduated to allow for instances of both Operating Instructions issued during Emergencies and Operating Instructions issued during non-Emergencies. Finally, the requirements should be modified to take into account Emergency and non-Emergency conditions. Failing to implement an Operating Instruction during a non-Emergency does not pose the same risk to BES reliability as failing to implement an Operating Instruction during an Emergency. Failing to implement an Operating Instruction during a non-Emergency would require other standards violations to cause a blackout. Under the current draft, all failures to comply with Operating Instructions could result in fine of \$1 Million per day, per violation. This does not seem reasonable, especially in the instance of a small generator or Distribution Provider that would have limited impact on reliability from failing to implement varying types of Operating Instructions.</p> <p>(4) Requirement R7 has reverted back to comparable Emergency procedures, which the drafting team has acknowledged in the rationale box of the previous posting as “impossible to measure.” Has the drafting team determined a way to measure and if so has it been documented?</p> <p>(5) Requirement R8 should be limited to known impacted Balancing Authorities and known impacted Transmission Operators “within the RC Area.” This modification would be consistent with R7. As currently written, R8 requires a TOP to inform all other BAs and TOPs in the Interconnection, as they would be impacted entities. Further, the percentages in the VSL do not accurately reflect the amount of entities that would need to communicate. The metric of 15 percent or less of the impacted TOPs assumes that 10 or more entities should be notified. In an Emergency, the RC and neighboring entities should be notified, as system operators should</p>

Organization	Yes or No	Question 1 Comment
		<p>be focused at mitigating the conditions leading to the Emergency. The RC is responsible for wide-area reliability.</p> <p>(6) Requirement R9’s VSL table needs to be modified. As written, a Severe VSL will result if a BA/TOP does not contact four or more known impacted interconnected entities. The requirement does not state how many entities must be contacted. If the BA/TOP contacts its RC, the burden should shift to the RC to coordinate with other impacted entities. The requirement needs to be clarified and VSL table should be modified.</p> <p>(7) Requirement R10 has improved with the removal of non-BES facilities.</p> <p>(8) Requirement R11 is duplicative with many of the NERC BAL standards. A BA is expected, as required by these BAL standards, to monitor the load-interchange balance and frequency its own area to calculate ACE as part of its efforts to maintain compliance with CPS1, CPS2, DCS, and eventually with the Balancing Authority ACE Limit, defined within NERC Standards BAL-001-2, and currently on file with FERC. Moreover, several other BAL requirements identify criteria that a BA must use to properly calculate its ACE and identify the need for redundant mechanisms to monitor the ACE components.</p> <p>(9) Requirement R15 is duplicative with R8. Both requirements address the TOP notifying the RC of actual operations that could result in an Emergency. Actions taken to return the system to within limits when a SOL has been exceeded could fall into this category. R15 should be struck.</p> <p>(10) The purpose statement is vague and overly broad and should be revised. The purpose of the Energy Policy Act of 2005 is to ensure reliability operation which by definition includes preventing instability, cascading, and uncontrolled separation. Thus, this is the purpose of the reliability standards as a whole. Furthermore, the way the purpose statement is written implies that instability, uncontrolled separation, and cascading may</p>

Organization	Yes or No	Question 1 Comment
		<p>not adversely impact the interconnection with the “that adversely impact the reliability of the Interconnection.” How would instability, uncontrolled separation, and cascading not adversely impact the interconnection?</p> <p>(11) Thank you for the opportunity to comment.</p>
<p><b>Response:</b> (1) The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and having agreed sees no reason to revise the current wording. As to data retention, the SDT points out that there are additional items cited in the measure that could be employed. No change made.</p> <p>(2) The Transmission Operator would certainly not sit by idly while frequency was declining. At the least, it would be expected to be in communication with the Balancing Authority and such communications may lead to the issuance of Operating Instructions. The requirement simply states that an entity maintain the reliability of its area through its own actions or by issuing Operating Instructions. If the entity does that, then the SDT believes it has met the spirit and intent of the requirement. No change made.</p> <p>(3) The Commission has made it clear in its Orders that it does not consider it appropriate to differentiate Operating Instructions according to the status of the system at the time of issuance. The belief is that this will lead to confusion for operators and possibly set up bad operating practices as to how to respond to Operating Instructions. Therefore, the SDT believes that the requirement should not attempt such differentiation. This would carry over to the VSLs as well. And it lends credence to the assignment of a High VRF. In addition, the approved TOP-001-1 has similar requirements with a High VRF. The SDT is obligated to maintain this VRF unless sufficient technical rationale can be provided to justify a change. To date, no one has provided such rationale. No change made.</p> <p>(4) The SDT added ‘comparable’ to the requirement language at the request of numerous entities in the previous posting. In its explanation for that change, the SDT expressed the belief that comparability would be sorted out after the fact. The important issue is to respond to the Emergency. No change made.</p> <p>(5) The SDT believes that the requirement language does not necessitate notification to all Balancing Authorities and Transmission Operators within the Interconnection as not all will be impacted by actions far from the source. No change made.</p> <p>(6) The SDT believes the current language is correct. The Reliability Coordinator should not arbitrarily be assigned the task of notifying other entities. The SDT believes that this is properly the role of the original Transmission Operator or balancing Authority. As for the VSL, the entity should know how many other entities are impacted and need to be notified which will allow for the VSL to be properly measured. No change made.</p>		

Organization	Yes or No	Question 1 Comment
<p>(7) Thank you for your support.</p> <p>(8) The SDT has investigated the BAL standards and believes that an explicit requirement for monitoring by the Balancing Authority is necessary. There are no specific requirements in BAL standards for the Balancing Authority to monitor. And the Commission has made it clear in previous Orders that one can't assume something based on other requirements that dictate certain actions. In this case, just because an entity has to adhere to requirements for AGC or DCS and that it can't do that without monitoring is not sufficient cause to not have a specific monitoring requirement. No change made.</p> <p>(9) The SDT believes that the two requirements are not duplicative. The conditions are decidedly different. Requirement R8 is referring to situations and notification for actions that cause, or could cause, an Emergency. Requirement R15 is referring to actions that were taken to relieve SOL exceedances. No change made.</p> <p>(10) The SDT believes that the Purpose Statement describes the intent of the accompanying standard. No change made.</p>		
PacifiCorp	No	<p>PacifiCorp does not favor approval of TOP-001-3 as drafted. PacifiCorp supports the comments of MidAmerica and objects for the following additional reasons: (1) The phrase "identified phase angle and equipment limitations" used in the proposed definition of Real-Time Assessment is vague, specifically the use of the term "identified." Clarification would be needed since compliance with R13 requires a Real-Time Assessment every 30 minutes. (2) In addition, not all EMS systems can monitor phase angles using current online tools. This technology is not available in our system and we are not sure when it will be.</p>
<p><b>Response:</b> The definition of Real-time Assessment has already been approved by industry and adopted by the Board. It was included with proposed TOP-001-3 for ease of reference and is not subject to change at this time. When crafting the definition, the SDT purposely included the term 'applicable' in front of all the listed items as a qualifier that would catch the situation described in the comment. If an entity doesn't have phase angle restrictions then that information is not applicable or identified. No change made.</p>		
Liberty Electric Power LLC	No	<p>The Operating Instruction should be identified as such by the issuing entity. Not identifying an Operating Instruction will lead to confusion over whether the instruction is a Marketing Instruction or an Operating Instruction. For example, a unit being released from the grid can self-dispatch if the release</p>



Organization	Yes or No	Question 1 Comment
		<p>is for economics. But if the release is considered an Operating Instruction due to conditions of which the GOP is not aware, a violation could occur. Suggest adding one word - Identified - to R3 prior to the term Operating Instruction.</p>
<p><b>Response:</b> The protocol for issuing Operating Instructions is beyond the scope of this project. However, if the protocol is followed, it is clearly evident when an Operating Instruction is issued. No change made.</p>		
<p>American Electric Power</p>	<p>No</p>	<p>R9: AEP disagrees with requiring notification of every planned and unplanned outage of 30 minutes or more, especially since the requirement could be interpreted as applying to the individual RTU’s themselves, and irrespective of their impact to the reliability of the BES. AEP believes the proposed language is overly prescriptive, does not accomplish the desired results of the SDT, and provides no benefit to the reliability of the BES. BAs and TOPs should be interested in knowing that they have quality data coming in, i.e., knowing whether or not the data is valid. There is no reliability benefit in requiring notification of every outage of every piece of equipment producing that data. PJM, for example, is in no position to know or determine how or if an individual RTU impacts reliability, or even the quality of the solution of a State Estimator. AEP believes it is far more important to know the *quality* of data feeding the applicable systems (for example, a state estimator), rather than the status of each piece of equipment in the systems which provide that data. AEP requests the drafting team articulate what reliability benefit they believe is gained by providing the status of individual pieces of equipment within R9. The phrase “all planned outages, and unplanned outages of 30 minutes or more” could have multiple interpretations. One possible interpretation is that the 30 minute threshold only applies to an unplanned outage, thereby inferring that notification be made for each and every planned outage, regardless of its duration. Another possible interpretation is that the 30 minute threshold</p>

Organization	Yes or No	Question 1 Comment
		<p>is used for both planned *and* unplanned outages. Please clarify this phrase to make it clear which outages the 30 minute threshold applies to.</p> <p>The text “between the affected entities” seems to imply inter-connections, even though it does not read as such earlier in R9 (known impacted interconnected entities).AEP recommends changing the language “all planned outages, and unplanned sustained outages” to simply say “all significant outages” and allow the TO and TOP to determine what is significant to the reliable operation of the BES.AEP voted affirmative on draft 3, a draft we consider superior in content to the draft currently proposed. AEP has chosen to vote negative on draft 4, driven by our objections to the latest revisions to R9, as expressed above.</p>
<p><b>Response:</b> The 30-minute threshold only applies to unplanned outages. All impactful planned outages require notification. However, the SDT does not agree that such verbal notifications necessarily go down to the RTU level. The SDT believes that ICCP quality code information is an acceptable form of communication and is included within the measure as “electronic communication”. Additionally, reporting requirements can also be covered as part of Operating Plans between the Transmission Operator and Reliability Coordinator. The intent of the standard is not to be administrative in nature. To use the provided example, if an entity is still going to receive valid data despite the loss of an RTU then that entity hasn’t been impacted by the outage and wouldn’t need to be verbally notified. Allowing entities to determine what is significant would lead to an inconsistent application of the requirement. No change made.</p>		
Puget Sound Energy	No	<p>The use of the word "maintain" instead of "address" raises the same issues as the word "ensure" in the previous drafts of this standard - if a reliability issue arises, an enforcement entity might find a violation of requirements R1 and R2 simply because an entity failed to "maintain the reliability" of its area (whether or not the entity’s operators took appropriate action to respond to the issue).</p> <p>In addition, the current draft does not address the burden associated with the need to demonstrate compliance with each Operating Instruction under requirement R3. I have previously commented on this issue and I continue</p>

Organization	Yes or No	Question 1 Comment
		to believe that the approach taken to Operating Instructions under the COM-002 standard more appropriately balances compliance burden with reliability needs.
<p><b>Response:</b> The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and having agreed sees no reason to revise the current wording. No change made.</p> <p>The SDT believes that it has addressed the burden associated with demonstrating compliance through the measure, data retention, and associated RSAW language regarding this issue. No change made.</p>		
Oncor Electric Delivery LLC	No	<p>Proposed Standard TOP-001-3 R9 States: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. In response to R9, Oncor recommends for the requirement to make it mandatory for BAs and TOPs to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it necessary to notify registered entities that do not have reliability control functions to the BES. Oncor’s suggested rewording for R9: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected TOs, TOPs and GOPs of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.</p> <p>Proposed Standard TOP-001-3 R10 States:R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations] 10.1. Within its</p>

Organization	Yes or No	Question 1 Comment
		<p>Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2. Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001- 3 does it require TOs to supply neighboring TOs with this data. Oncor requests R10.2 be removed from the standard due to lack of regional flexibility.</p> <p>Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to "a continuous duration exceeding its associated IROL Tv". This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncor’s recommendation is to keep the existing 30 minute time limit.</p>
<p><b>Response:</b> The SDT deleted the term ‘negatively’ in a previous posting following the receipt of numerous industry comments suggesting that it was redundant as entities wouldn’t be positively impacted by an outage. No change made.</p> <p>The requirement language is clear that Requirement R10, Part 10.2 only comes into play if the Transmission Operator finds that information necessary to determine SOL exceedances. If ERCOT is already operating without that information and is successfully meeting its obligations, then it must be the case that this information is not needed within ERCOT. Thus, ERCOT utilities would not be applying Requirement R10, Part 10.2. However, ERCOT is a special case dictated by its own rules and geography. Such a</p>		

Organization	Yes or No	Question 1 Comment
		<p>statement would not necessarily be true in other areas. Requirements are written on a continent-wide basis and thus the SDT believes the wording in Requirement R10, Part 10.2 is correct as stated. However, if a Transmission Operator does require Real-time data from a neighboring Transmission Operator, that Transmission Operator should be able to leverage Transmission Operator – Reliability Coordinator communications to obtain such data and not have to install additional Transmission Operator – Transmission Operator datalinks. No change made.</p> <p>There are already requirements and procedures in place that specify that the Reliability Coordinator determines IROLs and the associated <math>T_v</math>. See approved FAC-011-2. No change made.</p>
Ameren	No	<p>In our opinion, changes in this version were not significant and the drafting team has not addressed our concerns. (1) We have concerns on what constitutes "Operating Instructions", and over how an entity is to prove compliance once this standard becomes effective. We believe that "Reliability Directives", would be used infrequently under emergency type situations, compared to "Operating Instructions", everyday, common tasks, such as switching, would open up TOP's to an very burdensome way of documenting compliance. (2) We are concerned that the operator will have to focus less attention on the actual operation of the system, and more attention to collecting evidence for future audits. (3) We also have concerns about removing the terminology of EOP-001-1a; R1(and other requirements with similar language) that: "Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies." We believe that how entities choose to exercise that authority should be determined by each entity, based on their situation. (4) Over the years, the industry has clearly learned what a "Reliability Directive" means and we should not undo this concept, and avoid the confusion that it could create. In addition, the RSAWs introduce the concept of using BES events as a screening tool. We were not able to locate any such information in the Reliability Standard itself, nor</p>

Organization	Yes or No	Question 1 Comment
		does the standard give guidance on when there are no BES events for the period being audited.
<p><b>Response:</b> The Commission has made it clear in its Orders that it does not consider it appropriate to differentiate Operating Instructions according to the status of the system at the time of issuance. The belief is that this will lead to confusion for operators and possibly set up bad operating practices as to how to respond to Operating Instructions. Therefore, the SDT believes that the requirement should not attempt such differentiation. Operators should never be concerned about collecting audit evidence while operating the system. That should be done off-line and after-the-fact. The authority type requirements have been deleted as redundant as described in the mapping document. Reliability Directive was never an officially FERC approved term and confusion over what a reliability directive was or wasn't is what led to the revision of the COM standards and the creation of the definition of Operating Instruction. The appropriate measures include statements that an attestation that no events have occurred is sufficient evidence. No change made.</p>		
Indiana Municipal Power Agency	No	<p>IMPA does not agree with the use of Operating Instruction within this standard and does not agree with the SDT comments on how the RSAW will be used to “constrain” the potential amount of data an entity will need to provide to an auditor. NERC standards should be able to stand alone and not depend on RSAWs for guidance, especially since entities are audited to the requirements within a standard and not the RSAW. The RSAW states that auditors are encouraged to monitor compliance during the most “critical” events on the entity’s system. Once an auditor states that all Operating Instructions are critical to the BES, then data for all Operating Instructions will need to be supplied to the auditor or a listing of the Operating Instructions for the compliance period with a follow up of evidence (the entity still needs to keep all the evidence for every Operating Instruction for the compliance period just in case that is the one selected). By changing the “reliability directive” wording to “Operating Instruction” within requirements R3 and R5 of TOP-001-3, the SDT has increased the administrative burden on entities who receive Operating Instructions from their TOP and BA. Once again increasing the administrative burden on</p>

Organization	Yes or No	Question 1 Comment
		<p>entities is the opposite theme of the RAI program which has a goal of helping the industry to concentrate on the “risk” to the BES.</p>
<p><b>Response:</b> The SDT does not agree that it has increased the burden on entities to comply with these requirements and that sufficient safeguards have been put in place through data retention, measures, and RSAW language to prevent an undue burden on entities. No change made.</p>		
<p>CenterPoint Energy Houston Electric LLC</p>	<p>No</p>	<p>R10.2 - CenterPoint Energy agrees with the deletion of the phrase “non-BES” and appreciates the SDT’s consideration of industry comments. However, as stated in the previous round of comments, CenterPoint Energy strongly disagrees with the addition of 10.2 into the TOP Standards, specifically “neighboring Transmission Operator Areas”. CenterPoint Energy agrees with the Functional Model that it is the RC’s responsibility to monitor the wide area. In addition, CenterPoint Energy believes the SDT has overreached in its interpretation of paragraph 60 of the NOPR. CenterPoint Energy’s reading of paragraph 60 finds vague references to monitoring and analysis capabilities but no specific directives to expand the TOP’s view into another TOP Area. Also, CenterPoint Energy is concerned this will create confusion among registered entities as to who exactly has the responsibility to monitor and take action. Furthermore, CenterPoint Energy is not in favor of the most recent version of 10.2 where language referencing, “...identified as necessary by the Transmission Operator...” has been removed. As long as R10.2 remains CenterPoint Energy cannot support the proposed Standard and therefore strongly recommends the SDT delete R10.2.</p> <p>R13. - CenterPoint Energy agrees that an RTA should be run every 30 minutes, however during such events that could occur outside of the System Operator’s control (Ex. Loss of ICCP data); there should be a caveat as to when exceeding the 30 minutes becomes a violation. CenterPoint Energy suggests the following language: Each Transmission Operator shall</p>

Organization	Yes or No	Question 1 Comment
		<p>ensure that a Real-time Assessment is performed at least once every 30 minutes. In instances where a Real-Time Assessment cannot be performed (i.e. loss of ICCP data) the TOP shall take immediate action to restore Real-Time Assessment functionality.</p>
<p><b>Response:</b> The requirement language is clear that Requirement R10, Part 10.2 only comes into play if the Transmission Operator finds that information necessary to determine SOL exceedances. If ERCOT is already operating without that information and is successfully meeting its obligations, then it must be the case that this information is not needed within ERCOT. Thus, ERCOT utilities would not be applying Requirement R10, Part 10.2. However, ERCOT is a special case dictated by its own rules and geography. Such a statement would not necessarily be true in other areas. Requirements are written on a continent-wide basis and thus the SDT believes the wording in Requirement R10, Part 10.2 is correct as stated. However, if a Transmission Operator does require Real-time data from a neighboring Transmission Operator, that Transmission Operator should be able to leverage Transmission Operator – Reliability Coordinator communications to obtain such data and not have to install additional Transmission Operator – Transmission Operator datalinks. No change made.</p> <p>The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity’s obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:</p> <ol style="list-style-type: none"> <li>30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.</li> <li>Previous SDT comment responses have made clear that it doesn’t expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where</li> </ol>		



Organization	Yes or No	Question 1 Comment
		<p>normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.</p> <p>3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is restarted for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue.</p> <p>No change made.</p>
Consumers Energy Company	No	<p>Comments: M3 and M5 are over reaching in requiring: In such cases, the Balancing Authority, Generator Operator, and Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. In the case of generating equipment this can and often is conditional with operating constraints under certain conditions. There may not be specific rules written out to cover all conditions. This is often within the authority of the plant operator concerning what can be done safely with the equipment.</p>

Organization	Yes or No	Question 1 Comment
		This was not an evidence requirement in the current standards and does not need to be one now. We would be in favor of striking the above in both M3 and M5.
<p><b>Response:</b> If an operator is reacting to a particular situation by asserting that equipment limitations would be violated upon certain actions being taken, the SDT believes that the operator is acting based upon documented evidence stating so. The SDT also believes that if particular operating conditions are preventing an operator moving a unit to respond to a command that such constraints should have been made known to the Transmission Operator or Balancing Authority through the submission of revised operating limits which should prevent the Transmission Operator or Balancing Authority from requesting such movement. No change made.</p>		
Flathead Electric Cooperative	No	The change related to sustained outage being one more than 30 minutes seems tight. 30 minutes isn't very long for an outage.
<p><b>Response:</b> The SDT believes that 30 minutes is an appropriate timeframe as it is consistent with other standards such as approved EOP-004-2. No change made.</p>		
US Bureau of Reclamation	No	Reclamation continues to disagree with the use of the term Operating Instruction in TOP-001-3. The drafting team's response to concerns about use of the term "Operating Instruction" rather than reliability directive include "The proposal to use a new defined term 'Reliability Directive' is no longer being considered" and "Reliability Directive was never approved by FERC and thus was never part of an officially approved standard. The SDT believes that the use of Operating Instruction in this standard is consistent with the purpose and intent of the COM standards and that the COM standards correctly captured the reliability need as indicated in FERC's acceptance of the standards. In the FERC NOPR, it was made clear that the concept of a special type of communication for Emergency situations was not considered acceptable. Operating Instructions issued to generators are not intended to damage critical generating equipment or interfere with competing obligations (e.g., water delivery schedules for hydroelectric producers)."Reclamation respectfully disagrees with the drafting team's

Organization	Yes or No	Question 1 Comment
		<p>interpretation. Reclamation believes that FERC Order directed NERC to define "directive" rather than extend the scope of the standard to all communications between entities regarding bulk electric system operations. The order stated that the proposed standard had defined "transmission operator directives only in emergencies, not normal or pre-emergency times." Reclamation agrees with FERC that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements)." In Reclamation's opinion, the FERC order only directed NERC to better define the term "directive" and allow directives to be issued during normal operations as well as pre-emergency and emergency situations. Reclamation does not believe that FERC required the standard to apply to all non-emergency conversations between GOPs, BAs, and TOPs, with mutually-agreed upon operating plans resulting from these conversations like the COM updates. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Reclamation does not believe that Transmission Operators always understand or consider the equipment capabilities and limitations, or other obligations of generators, and without this understanding Transmission Operators should not have authority for every operating instruction to be mandatory. Reclamation believes that Balancing Authorities and Transmission Providers should be granted wide latitude to issue "directives," which could be defined as "mandatory operating instructions to address transmission system concerns," but directives should be clearly identified by the transmission operator as directives to inform the recipient of the critical nature of the instruction. As written, the standard would instead apply to all operating instructions in all situations, and essentially would allow transmission operators to dictate instructions without understanding competing safety, equipment,</p>

Organization	Yes or No	Question 1 Comment
		<p>regulatory and statutory (including environmental) concerns of generators. This is likely to degrade BES reliability because generator operators will no longer understand the criticality of transmission operator instructions identified as "directives." Reclamation does not believe that the requirements to comply with Reliability Directives in TOP-001 and IRO-001 should be invoked unless the Transmission Operator describes a mandatory instruction as a Reliability Directive.</p> <p>Reclamation appreciates the clarifying language changes in R16, M16, R17, and M17.</p>
<p><b>Response:</b> The Commission has made it clear in its Orders that it does not consider it appropriate to differentiate Operating Instructions according to the status of the system at the time of issuance. The belief is that this will lead to confusion for operators and possibly set up bad operating practices as to how to respond to Operating Instructions. Therefore, the SDT believes that the requirement should refrain from attempting such differentiation. No change made.</p> <p>Thank you for your support.</p>		
Ingleside Cogeneration, LP	No	<p>Ingleside Cogeneration L.P. (ICLP) believes that the project team has found an excellent resolution to the issue surrounding "sub-100 kV" and "non-BES" element data. By relying on other standards such as FAC-011-2 - which allows the Reliability Coordinator to dictate that the TOP must consider such facilities while developing their SOLs - the intent is still captured in a binding manner. In addition, NERC's BES exception process allows the forced registration of critical facilities, which clearly applies to those that would affect a System Operating Limit. The TOP still has the obligation and authority to derive/monitor every SOL, but is not subject to the opinion of a CEA who may think that the criteria used is insufficient.</p> <p>Unfortunately, no such insight has been employed to defuse the standoff related to the execution of "Operating Instructions". The issue caught FERC's attention originally as the term "Reliability Directive" was used in</p>

Organization	Yes or No	Question 1 Comment
		<p>the submission of TOP-001-2 - which only applied to situations where an Emergency was declared. The Commission felt that instructions issued by a BA/TOP during near-emergency and normal operating conditions should also be mandatory, which the in-effect version of TOP-001 does not preclude. (It uses the generic un-capitalized term “reliability directive” which can apply to most any communication requiring action by the recipient.) The attempt to clarify the proper situations where a reliability directive can be used, and the evidence required to demonstrate compliance, has led to this impasse. ICLP believes that the way TOP-001-3 is written now, a GOP will be expected to capture the fact that every Operating Instruction was performed, even in low-risk situations where status or routine action is requested. This works against the concept of risk-based compliance and adds an administrative burden that is disproportional to the expected benefits. ICLP believes there is an acceptable alternative. The project team can lessen the severity of the improper execution of an Operating Instruction as compared to a Reliability Directive. This would mean that any instruction not identified by the BA or TOP as a Reliability Directive would only carry a Low VRF if not executed properly - perhaps a High VRF if an EOP-004-2 defined Event took place as a result. Furthermore, the lack of documentation should not work against the recipient of an Operating Instruction, but would allow for mitigating considerations if a good faith attempt was made in its execution. This would encourage the GOP (in our case) to diligently capture every Operating Instruction, but would not lead to a violation when an understandable oversight took place.</p>
<p><b>Response:</b> Thank you for your support.</p> <p>The Commission has made it clear in its Orders that it does not consider it appropriate to differentiate Operating Instructions according to the status of the system at the time of issuance. The belief is that this will lead to confusion for operators and possibly set up bad operating practices as to how to respond to Operating Instructions. Therefore, the SDT believes that the requirement</p>		

Organization	Yes or No	Question 1 Comment
<p>should not attempt such differentiation. The SDT believes that it has appropriately identified and considered the burden on entities to comply with these requirements and that sufficient safeguards have been put in place through data retention, measures, and RSAW language to prevent an undue burden on entities. No change made.</p>		
<p>Independent Electricity System Operator</p>	<p>No</p>	<p>1. We continue to have serious concerns over the proposed retirement of TOP-004-2 Requirement R4 without having some of the requirements in TOP-004-2 revised to address the reliability need for confirming and re-establishing valid SOLs/IROLs in an unknown or unstudied state. We believe that there are times when, following some power system event, when there are no derived set of limits - particularly transient stability limits. We believe that the revised TOP standards do not compel an entity to derive limits following such events within an acceptable time frame. That direction was clearly specified in the existing TOP-004-2 R4:R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. We believe that removal of this requirement, without adequately and clearly replacing it, significantly diminishes reliability. We submit the following detailed comments for consideration by the SDT: a. The SDT's response to our previous comment suggests there is always either a set of limits in service or an Operating Plan which provides guidance to adjust the limit until a new set of limits are analyzed and determined. We are unable to find a requirement in the standard that stipulates the Operating Plan shall have guidance to adjust the limit until a new set of limits are analyzed and determined. This requirement doesn't appear to exist. b. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined, what to do upon experiencing an SOL exceedance, and acceptable timeframes to mitigate SOL exceedances. The above response addresses SOL exceedance only; but the issue we raised is on the need to re-establish SOLs themselves, which may not already exist for the</p>

Organization	Yes or No	Question 1 Comment
		<p>conditions encountered. How does an entity know if it has exceeded an SOL if an SOL was not previously developed or is invalidated by the prevailing conditions? c. The SDT believes that the situation described has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to Requirement R13, perform a Real-time Assessment every 30 minutes, and Requirement R14, implement Operating Plans to mitigate an SOL Exceedance, as well as the guidance provided on Operating Plans in Section F. Furthermore the standard does not prohibit an entity from performing an RTA more frequently in response to an unplanned system event. The SDT’s response suggests that the concept of confirming and re-establishing SOL’s is covered in the entities’ Operating Plan. An Operating Plan, consistent with the NERC definition, is general and predictive in nature and by itself does not mandate the confirmation or re-establishment of limits when in an unstudied state. The concept of confirming and re-establishing SOL’s for the prevailing condition is only captured in the SOL Exceedance White Paper under the “Stability Limit Exceedance” section as follows: “Pre-determined Transient and voltage Stability limits must be re-established when changes in the system (both expected future changes and actual Real-time changes) occur that render these pre-determined limits invalid.” This sentence is presented in a standard requirement language. We do not understand why this is not stipulated in the standard itself such that it becomes an enforceable requirement to address the potential reliability gap created by retiring TOP-004-2 Requirement R4. Having this language in a whitepaper does not make this mandatory.</p> <p>2. We offer the following comments on three requirements in TOP-001-3:i. R7: We do not agree with the added qualifier “within its Reliability Coordinator Area” since we believe that all TOPs need to assist their neighbor TOPs regardless if they are in the same RC area. We propose to remove this qualifier from R7.ii.</p>

Organization	Yes or No	Question 1 Comment
		<p>R10: We understand the intent of the proposed changes to Parts 10.1 and 10.2, but these changes have made the two parts confusing and inconsistent. From a reliability standpoint, it is intuitive that a TOP needs to monitor all Facilities within its TOP area that may have an impact on SOLs/IROLs. Part 10.1 is unclear on this whereas Part 10.2 is more specific on the parameters of the concerned Facilities. We suggest adding the word “all” before “Facilities” in Part 10.1.iii.</p> <p>R11: This requirement is redundant with BAL-002 since the latter already requires a BA to assess all contingencies - which should include SPS operations resulting in generation and/or load reduction, to determine its reserve requirements. We suggest removing R11.</p>
<p><b>Response:</b> The SDT understands the concern of moving to an unknown state which it interprets as a condition that has not been previously studied. However, the SDT believes that there is always either a set of limits in service or an Operating Plan which provides guidance to adjust the limit until a new set of limits are analyzed and determined. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined, what to do upon experiencing an SOL exceedance, and acceptable timeframes to mitigate SOL exceedances. The SDT believes that the situation described has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to Requirement R13, perform a Real-time Assessment every 30 minutes, and Requirement R14, implement Operating Plans to mitigate an SOL Exceedance, as well as the guidance provided on Operating Plans in Section F and the SOL Exceedance White Paper. Furthermore, the standard does not prohibit an entity from performing a Real-time Assessment more frequently in response to an unplanned system event. No change made.</p> <p>R7 – The SDT believes that there must be coordination at the Reliability Coordinator level before a Transmission Operator provides assistance to an entity outside of its associated Reliability Coordinator Area. No change made.</p> <p>R10 – The SDT believes that the new sentence structure employed in the previous posting alleviates any ambiguity or confusion. No change made.</p> <p>R11- The SDT has investigated the BAL standards and believes that an explicit requirement for monitoring by the Balancing Authority is necessary. There are no specific requirements in BAL standards for the Balancing Authority to monitor. And the Commission has made it clear in previous Orders that one can’t assume something based on other requirements that dictate certain actions. In this</p>		



Organization	Yes or No	Question 1 Comment
<p>case, just because an entity has to adhere to requirements for AGC or DCS and that it can't do that without monitoring is not sufficient cause to not have a specific monitoring requirement. No change made.</p>		
<p>American Transmission Company, LLC</p>	<p>No</p>	<p>ATC recommends that the SDT consider removing the following language from the proposed "Real-time Assessment" definition: "known Protection System and Special Protection System status or degradation," The revised definition would be as follows: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) Reason for removal of the language: This language should be removed because it is unrealistic for entities to perform a new real-time assessment every 30 minutes that incorporates the necessary contingency definition changes driven by a protection system failures. EMS systems using real-time contingency analysis tools do not include contingency definitions for the myriads of potential tripping scenarios for various failed protection systems. Therefore, off-line analysis would need to be performed by the system operator or another employee. Because off-line analysis would need to be used, it is an unreasonable burden to have to perform this assessment every 30 minutes as would be required by the proposed Requirement R13.</p>
<p><b>Response:</b> The definition of Real-time Assessment has already been approved by industry and adopted by the Board. It was included with proposed TOP-001-3 for ease of reference and is not subject to change at this time.</p> <p>The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the</p>		

Organization	Yes or No	Question 1 Comment
		<p>responsibility to maintain an entity’s obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:</p> <ol style="list-style-type: none"> <li>1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.</li> <li>2. Previous SDT comment responses have made clear that it doesn’t expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where normal methods aren’t operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn’t be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.</li> <li>3. There are additional elements to the timing question that need to be considered as well. The requirement doesn’t mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is restarted for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating</li> </ol>

Organization	Yes or No	Question 1 Comment
<p>Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue.</p> <p>No change made.</p>		
<p>Georgia Transmission Corp</p>	<p>No</p>	<p>(1) GTC requests the drafting team to develop separate requirements for the DP to comply with Operating Instructions received by the TOP and BA which is consistent with NERC’s Functional Model relating to real-time switching activities at non-BES facilities. By making this change, the requirements will be made clearer that the Operating Instructions that the DP receive from the TOP with respect to the defined term Operating Instruction, correspond to switching non-BES facilities that “impact” the output of an Element of the BES (shed or shift load). GTC believes the typical scenario the drafting team is considering is from a TOP control center to a DP dispatch center that does not own BES equipment, but can impact the output of an Element of the BES (by shedding or shifting load). The aforementioned comments relating to DP switching non-BES facilities provides additional support of why the DP should be ungrouped with the BA and GOP which may own and operate BES facilities. This separation of BES vs non-BES associated with implementing Operating Instructions reduces the current ambiguity for those NERC registered DPs that are also registered as Transmission Owners but are not registered as Transmission Operators with respect to requirements R3 and R5. With the following changes made to the requirements, GTC would be comfortable voting affirmative on this standard:</p> <ul style="list-style-type: none"> <li>o Each Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator to reduce voltage, shed load, shift load, and/or implement system restoration plans on non-BES facilities unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.</li> <li>o Each Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority to reduce voltage,</li> </ul>

Organization	Yes or No	Question 1 Comment
		<p>shed load, or shift load on non-BES facilities unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.</p> <p>(2) If however, the current draft standard passes this ballot GTC would greatly appreciate for the Standard Drafting team to expand the Rationale for Requirement R3 corresponding with the DP by inserting the following language: As identified in the NERC functional Model, Distribution Provider’s must perform switching tasks to implement voltage reduction, load shed, or as part of a system restoration plans as directed by the Transmission Operator or Balancing Authority.</p> <p>(3) This Standard does not apply to a Transmission Owner; will the drafting team confirm GTC’s assumption that the recipient field personnel of an Operating Instruction who performs the switching inside “transmission stations” are assumed to be handled by the TOP via R1?</p> <p>(4) The recipient entities of Operating Instructions performed in the field that do not own control centers will rely on the operator logs and voice recordings of the issuing entities as compliance evidence. Those entities (issuing vs recipient) which may have different data retention periods for compliance enforcement protection increases compliance risk to recipient entities that have zero control over the data. This risk can be mitigated by incorporating a reasonable data retention period into the requirements that are consistent with compliance enforcement practices. It should be noted, that the 90 day retention period under section C of this standard does not align with any compliance enforcement Regional Entity expectations and only adds confusion.</p>
<p><b>Response:</b> (1) and (2) –The SDT intent is that Operating Instructions will be issued in accordance with the Functional Model. No change made.</p> <p>(3) The SDT confirms the commenter’s interpretation.</p>		

Organization	Yes or No	Question 1 Comment
(4) The SDT believes that the data retention periods provided in the standard are fair and reasonable. No change made.		
ReliabilityFirst	No	<p>ReliabilityFirst abstains and offers the following comments for consideration.</p> <p>1. Requirement R1, R2, R3 and R4 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Failure to do so could result in a situational awareness issue (i.e. lack of accurate data and information) for the System Operator that could jeopardize system reliability. Additionally, and absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst understands that a finite timeframe may not be appropriate to be stated in the standard to cover all circumstances, but offers a suggestion to require the TOP to define its needs when issuing Operating Instructions. ReliabilityFirst suggests the following revised language for consideration. R1 - Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions [along with allocated time constraints for notification if the Operating Instructions cannot be performed].R2 - Each Balancing Authority shall act to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instruction [along with allocated time constraints for notification if the Operating Instructions cannot be performed].R4 - Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within the time constraints allocated by the Transmission Operator] of its inability to perform an Operating Instruction issued by its Transmission Operator..." R6 - Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within the time constraints allocated by the Balancing</p>

Organization	Yes or No	Question 1 Comment
		<p>Authority] of its inability to perform an Operating Instruction issued by that Balancing Authority.”</p> <p>2. Requirement R10, Part 10.1 and 10.2 - ReliabilityFirst believes the lead-in language in R10 (“...shall perform”) does not read well with the two sub parts. ReliabilityFirst recommends the following for consideration in order to make the wording of the parent and sub parts read more clearly: a. 10.1 - Monitoring Facilities and the status of Special Protection Systems, within its Transmission Operator Area, and b. 10.2 - Obtaining and utilizing status, voltages, and flow data for Facilities and the status of Special Protection Systems, outside its Transmission Operator Area.</p> <p>3. Requirement R12 - ReliabilityFirst requests clarification from the SDT for instances when a TOP identifies an IROL which is outside of the set of predefined identified IROLs, are the TOPs also required to not operate outside these unidentified IROLs per Requirement R12?</p> <p>4. Requirement R14 - ReliabilityFirst believes the word “initiate” should be replaced with the word “execute”. Because Operating Plans consist of “...a group of activities”, we would not want to only require the TOP to start (i.e., initiate) the first activity of the Operating Plan, but execute all activities that are part of the Operating Plan to mitigate the issue at hand.</p>
<p><b>Response:</b> 1. The SDT believes that it is counter to reliability to place a time tag on these requirements. The operator should be concentrating on the reliability issue and not be concerned with adhering to an arbitrary time period for informing entities. No change made.</p> <p>2. The SDT believes the suggested change doesn’t provide any additional clarity. No change made.</p> <p>3. The Reliability Coordinator identifies IROLs. If the Reliability Coordinator has not identified an IROL and provided that information to the Transmission Operator, then the Transmission Operator would not know about the IROL and would operate according to the information it has in hand. If the Transmission Operator observes an anomaly that it can’t explain, then good utility practice would</p>		

Organization	Yes or No	Question 1 Comment
<p>dictate that it inform its Reliability Coordinator of this anomaly which should precipitate action on the part of the Reliability Coordinator.</p> <p>4. The SDT believes the suggested change doesn't provide any additional clarity. No change made.</p>		
<p>Texas Reliability Entity, Inc.</p>	<p>No</p>	<p>WRT to Requirement 10: Should Remedial Action Scheme be used instead? How will an entity support "as necessary"? How will a CEA accept "as necessary"? Transmission Operator Area ignores a Transmission Operator that DIRECTS "the operations of the transmission facilities" and may cause a reliability gap in the Standard in this Interconnection.</p> <p>The VSLs are geared towards zero tolerance. Example- R8 appears to be a violation if one TOP is not informed. R10 High VSL is one item is not monitored (Is that one line?)</p> <p>The R8 VSL adding a component to the R8 Requirement that does not otherwise exist in R8. This VSL modification of the R8 Requirement weakens the Requirement's beneficial effect on the reliability of the BES. In effect, the VSL modification negates the requirement in R8 by adding at the end 'unless you can't'. The added phrase in the VSL needs to be added in the R8 Requirement, where it can be properly considered as part of the Requirement, or removed from the VSL. R8 VSL has the phrase "when conditions did permit such communications" added to the description of the violations. This phrase does not exist in the Requirement. If the SDT wishes to change the meaning of the Requirement it should add that quoted phrase to the Requirement itself.</p> <p>R16 VSL has unintentionally included "Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its" in</p>

Organization	Yes or No	Question 1 Comment
		<p>the VSL and the quoted section should be removed. Also change the two occurrences of “Balancing Authority” to “Transmission Operator”.</p> <p>R17 VSL has unintentionally included “Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its” in the VSL and the quoted section should be removed.</p> <p>The removal of the phrase "may be performed either a day ahead or as much as 12 months ahead" in the revised definition of Operational Planning Analysis may impact the Real-time reliability of the Reliability Coordinator Area. The issue is that the new definition only refers to next-day operations. There is a possible gap since a time frame for the evaluation of one day up to 12 months may not be considered by registered entities because of the removal of the subject language. This gap is compounded by the fact that the Time Horizons for most of the requirements are either Same Day or Real-Time.</p>
<p><b>Response:</b> The change from Special Protection Scheme to Remedial Action Scheme will be performed as part of an overarching project to correct all standards and requirements once final approval of the definition is obtained. The term ‘as necessary’ provides for the entity that best knows the situation to make a determination as to what information it needs. The SDT can’t comment on how the CEA will interpret any aspects of the standard. The SDT fails to see how Transmission Operator Area causes a gap.</p> <p>The SDT believes that the VSLs are not directed toward zero tolerance but does agree that the VSLs do apply to missing one element. No change made.</p> <p>The SDT agrees and has deleted the phrase from the VSLs. See the red-lined standard for the change.</p> <p>The SDT agrees and has deleted the language in both VSLs. See red-lined standard for the change.</p> <p>The definition of Operational Planning Analysis has already been approved by industry and adopted by the Board. It was included with proposed TOP-001-3 for ease of reference and is not subject to change at this time. The SDT believes that the true requirement</p>		



Organization	Yes or No	Question 1 Comment
<p>is to make certain that a next-day analysis is performed and that other timeframes are not mandatory. Proposed IRO-017-1 takes into account planning for other timeframes. No change made.</p>		
<p>Electric Reliability Council of Texas, Inc.</p>	<p>No</p>	<p>ERCOT respectfully submits the following comments: 1. Regarding Requirement R13, ERCOT requests clarification that Requirement R13 does not apply during time periods where entities lose telemetry or EMS (an abnormal or emergency condition). During such time periods, registered entities may not be able to perform a Real-Time Assessment within 30 minutes (per definition). The reliability standards contemplate and allow for emergency circumstances and emergency plans in other Reliability Standards. To ensure consistency, the SDT should provide clarification regarding the applicability of this requirement by either: limiting applicability to normal operating conditions; providing a metric for percentage of availability that constitutes compliance, or revising the requirement to account for system issues as mentioned.</p> <p>2. ERCOT reiterates concerns regarding use of the term “Operating Plan” in Requirement R14. Because the definition of “Operating Plan” states that it is a “document”, use of the term “Operating Plan” may be too restrictive to allow for necessary actions to be taken as contemplated in Requirement R14 as most actions taken occur per procedures or constraint management plans, but the universe of responsive actions cannot be easily documented in a single “document”. To ensure that system operators have the flexibility needed to take whatever actions they deem necessary to mitigate an SOL, ERCOT suggests removal of the term Operating Plan.</p> <p>3. ERCOT respectfully submits that Requirements R1 and R2 are unnecessary because they are redundant with other requirements for a BA and TOP in Same-Day and Real Time Operations. ERCOT suggests deletion of Requirements R1 and R2.</p>

Organization	Yes or No	Question 1 Comment
		<p><b>Response:</b> The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity’s obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:</p> <ol style="list-style-type: none"> <li>1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.</li> <li>2. Previous SDT comment responses have made clear that it doesn’t expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where normal methods aren’t operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn’t be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.</li> <li>3. There are additional elements to the timing question that need to be considered as well. The requirement doesn’t mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is re-started for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the</li> </ol>

Organization	Yes or No	Question 1 Comment
<p>meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue.</p> <p>No change made.</p> <p>Given the clarification provided in Section F regarding the SDT’s intent with the use of Operating Plan, the SDT believes that the term is used correctly in the requirement. No change made.</p> <p>The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and therefore, the SDT sees no reason to revise the current wording. No change made.</p>		
<p>Dominion</p>	<p>Yes</p>	<p>4. Applicability: Suggest that “4.5” be struck as Load Serving Entity was deleted from the applicability list of entities.</p> <p>Dominion suggests that the Rationale for Requirement R13: be modified to state, “...and the timeframe is copied from the approved IRO-008-1, Requirement R2 for consistency.”, as the language is not verbatim from approved IRO-008-1 Requirement 2.</p> <p>M5 - Suggest the “(s)” behind Balancing Authority be removed to match R5.</p>
<p><b>Response:</b> The SDT agrees and has corrected the typo. See redlined standard for change.</p> <p>The language cannot be verbatim as the two standards refer to different entities. The SDT sees no additional clarity being provided by the suggested change. No change made.</p> <p>The SDT agrees and has made the suggested change. See summary consideration for actual wording.</p>		
<p>PJM Interconnection</p>	<p>Yes</p>	<p>PJM supports the standard and appreciates the changes made by the SDT.</p>
<p><b>Response:</b> Thank you for your support.</p>		

END OF REPORT