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 30-day public comment period from October 10, 2014 through November 10, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 47 sets of comments, including comments from approximately 133 different people from approximately 100 companies representing all 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.

The SDT has made the following changes due to industry comments:

- Requirement R1 – removed the 'direct action' language to alleviate concerns about potential double jeopardy issues as direct actions are included in other standards and requirements where necessary; replaced 'address' with 'maintain'.
- Requirement R2 - removed the 'direct action' language to alleviate concerns about potential double jeopardy issues as direct actions are included in other standards and requirements where necessary; replaced 'address' with 'maintain'.
- Requirements R3, R4, R5, and R6 – removed the Load-Serving Entity as an applicable entity following the recent Board of Trustees (Board) action on removing Load-Serving Entity as a functional entity. (Note – Load-Serving Entity was not removed from proposed IRO-010-2 or proposed TOP-003-3 as those standards have already been approved by industry and adopted by the Board. Load-Serving Entity will be removed from those standards when the overarching project to remove Load-Serving Entity is initiated.)
- Requirement R7 – Added the phrases 'within its Reliability Coordinator Area' (as Transmission Operators will only be expected to react to requests from other Transmission Operators within the Reliability Coordinator Area and any assistance for Transmission Operator Areas outside the Reliability Coordinator Area will be done through requests from the Reliability Coordinators) and 'comparable' assistance (to assure that a Transmission Operator isn't asked to do go further than the requesting Transmission Operator has done).
- Requirement R9 – added 'known' as a qualifier for impacted entities; clarified that the requirement is for all outages by adding 'planned and unplanned' as qualifiers to outages; replaced 'sustained' by '30 minutes or more' to achieve clarity and consistency with other standards.
- Requirement R10 – deleted the phrase 'non-BES' as any need for non-BES data will be defined in the Reliability Coordinator SOL methodology and included in BES as part of BES Exception Process as necessary; clarified that an entity does not have to 'monitor' outside of its Transmission Operator Area – it only needs to utilize necessary data.

- Requirement R11 – replaced the phrase 'perform its reliability functions' with more specific language – 'maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency'.
- Requirement R15 – capitalized 'System'
- Requirement R16 – made the language for the list of applicable outages consistent with that of the language in Requirement R9.
- Requirement R17 - made the language for the list of applicable outages consistent with that of the language in Requirement R9.
- Made commensurate changes in matching Measures and cleaned up language in Measures M8 and M12.
- Made commensurate changes to VSL language and changed the VSL for Requirement R11 from binary to incremental.
- Added language to the SOL Exceedance White Paper explaining that the Reliability Coordinator's SOL methodology will specify requirements to include any non-BES data or external data in order for a Transmission Operator to determine SOLs in accordance with the Reliability Coordinator's SOL methodology.

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 . In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: 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 Electricity 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.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
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	Patricia Robertson	BC Hydro	X	X	X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Venkataramakrishnan Vinnakota	BC Hydro	WECC	2
2.	Pat G. Harrington	BC Hydro	WECC	3
3.	Clement Ma	BC Hydro	WECC	5

3.	Group	Sandra Shaffer	PacifiCorp						X				

N/A

4.	Group	Erika Doot	Bureau of Reclamation	X				X					

N/A

5.	Group	Kelly Dash	Con Edison, Inc.	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Bedder	Orange & Rockland Utilities	NPCC	NA

6.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Ken Goldsmith	Alliant Energy	MRO	4
8.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
9.	Marie Knox	MISO	MRO	2
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
11.	Randi Nyholm	Minnesota Power	MRO	1, 5
12.	Scott Nickels	Rochester Public Utilities	MRO	4
13.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
14.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terri Pyle	Oklahoma Gas & Electric	SPP	1
2.	Don Hargrove	Oklahoma Gas & Electric	SPP	3
3.	Leo Staples	Oklahoma Gas & Electric	SPP	5
4.	Jerry Nottnagel	Oklahoma Gas & Electric	SPP	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	Brandy Spraker		SERC	5
4.	Marjorie Parsons		SERC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
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
5.	Dennis Sismaet	Seattle City Light	WECC	6

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Kathleen Black	DTE Electric Co.			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5
4.	Neil Kennings	Renewable Energy	RFC	
5.	Barbara Holland	SOC	RFC	
6.	Alan Randolph	Fossil Generation	RFC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Marcus Pelt	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

N/A

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee (SRC)		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Bilke	MISO	RFC	2
2.	Ali Miremadi	CAISO	WECC	2
3.	Charles Yeung	SPP	SPP	2
4.	Kathleen Goodman	ISO-NE	NPCC	2
5.	Christina Bigelow	ERCOT	ERCOT	2
6.	Catherine Wesley	PJM	RFC	2
7.	Ben Li	IESO	NPCC	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
2.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
4.	Ryan Strom	Buckeye Power, Inc.	RFC	3, 4, 5
5.	John Shaver	Arizona Electric Power Cooperative/ Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
6.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
7.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1
8.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
9.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
10.	Ginger Mercier	Prairie Power, Inc.	SERC	3
11.	Alvis Lanton	Southern Illinois Power Cooperative	SERC	1, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
3.	Robert Hirchak	CLECO Corporation	SPP	1, 3, 5, 6
4.	Mike Kidwell	Empire District Electric Company	SPP	1, 3, 4
5.	James Nail	City of Independence, Missouri	SPP	3, 5
6.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5

7.	Sing Tay	Oklahoma Gas and Electric Company	SPP	1, 3, 5, 6
8.	Jeff Wells	Grand River Dam Authority	SPP	1
9.	J. Scott Williams	City Utilities of Springfield	SPP	1, 4
10.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
11.	Robert Rhodes	Southwest Power Pool	SPP	2
12.	Shannon V. Mickens	Southwest Power Pool	SPP	2

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
18.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Anasis	Technical Operations	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Individual	Steve Alexanderson	Central Lincoln People's Utility District			X	X					X	
20.	Individual	Muhammed Ali	Hydro One	X		X							
21.	Individual	Thomas Lyons	Owensboro Municipal Utilities			X							
22.	Individual	Roger Dufresne	Hydro-Quebec Production					X					
23.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X							
24.	Individual	David Jendras	Ameren	X		X		X	X				
25.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
26.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
27.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
28.	Individual	Robert Fox on Behalf of David Austin	NIPSCO	X		X		X	X				
29.	Individual	Diane Barney	New York State Department of Public Service									X	
30.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
31.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
32.	Individual	Denise M. Lietz	Puget Sound Energy	X		X		X					
33.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
34.	Individual	Anthony Jablonski	ReliabilityFirst										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Leonard Kula	Independent Electricity System Operator		X								
36.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
37.	Individual	Rich Salgo	NV Energy					X					
38.	Individual	Joshua Smith	Oncor Electric Delivery LLC	X									
39.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
40.	Individual	Sonya Green-Sumpter	South Carolina Electric & Gas	X		X		X	X				
41.	Individual	Daniel Duff	Liberty Electric Power					X					
42.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
43.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
44.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC	X		X							
45.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
46.	Individual	Jeremy Voll	BEPC	X		X		X		X			
47.	Individual	Daniel Mason	HHWP	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 you for your contributions.

Organization	Agree	Supporting Comments of "Entity Name"
Seattle City Light	Agree	NPCC
Hydro-Quebec TransEnergie	Agree	NPCC
Kansas City Power and Light	Agree	SPP - Robert Rhodes
BEPC	Agree	Basin Electric agrees with the comments provided by the NRECA and Georgia Transmission Corporation.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		

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 made the following changes due to industry comments:

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(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 Balancing Authority, Generator Operator, 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. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

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 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, 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 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 Balancing Authority.

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or 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. If no request for assistance was received, the Transmission Operator may provide an attestation.

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. 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. If no such situations have occurred, the Transmission Operator may provide an attestation.

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.

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified 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. 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. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and

10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltages, and flow data for Facilities and the status of Special Protection Systems as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

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 Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors 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.

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

M16. Each Transmission Operator 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 Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

M17. 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 telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

Changes to VSLs due to industry comments are shown in the redlined version of the standard.

Changes to the SOL Exceedance White Paper are shown in the redlined version of the paper provide for the fourth posting.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	We commented in the last posting to replace the word “ensure” in requirements R1 and R2, and in the standard’s other requirements where applicable. We note that “ensure” has been replaced with “address”. The Purpose of the standard is “To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.” “Maintain” or “restore” are more appropriate words to use than “address”. The Time Horizon should only be “Real-time Operations”. “Ensure” in Measure M1 should also be replaced with the word selected to be used in R1. Regarding Requirement R3, Time Horizons should only be “Real-time Operations”. The 30 minute requirement in Requirement R13 is too restrictive and is 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: o Each Transmission Operator shall perform a Real-time Assessment at least once every two hours. o Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes when the EMS and SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform Real-time assessments within two hours.

Organization	Yes or No	Question 1 Comment
		Requirement R7 has removed an important concept of TOP-001-1a Requirement R6. A supporting TOP should not be obligated to activate emergency procedures beyond those activated by the TOP that is in the emergency. As an example, a supporting TOP should not be obligated to go into voltage reduction if the TOP with the emergency as not take the same voltage reduction action first. Simply stating, '... has implemented its Emergency procedures,' is not specific. TOP-001-1a Requirement R6 reads: R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. Recommend the following change to R7 to target the TOP's requirement to assist other TOPs to those in the same RC area: R7. Each Transmission Operator shall assist other Transmission Operators within their Reliability Coordinator's region, if requested and able, provided that the requesting entity has implemented its Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations] In Part 10.2 the phrase '... as necessary by the TOP' is unclear. What TOP? Part 10.2 should be revised to be consistent with Part 10.1 and read: 10.2. Outside its Transmission Operator Area: Sub-parts 10.1.3 and 10.2.3 should be made consistent. "Ensure" remains in the posted requirement R13. Suggested rewording R13: Each Transmission Operator shall perform or have performed a Real-time Assessment at least once every 30 minutes. The "s" in system should be capitalized in Requirement R15.

Organization	Yes or No	Question 1 Comment
		R3, M3, M4, R5, M5, M6 all use the words to comply with operating instructions, but R4 and R6 use the words perform an operating instruction. The wording should be consistent. Measure M7 should be corrected to be written like M3 and M5 in the past tense: "...unless such assistance could not be physically implemented..." Measure M8 should be revised since R8, and the first part of M8 refer to operations "that result in, or could result in, an Emergency". Therefore, the last sentence in M8 should read: "If no such situations have occurred, the TOP may provide an attestation." Requirement R11 directs the Balancing Authority to "...monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load...". Monitoring Special Protection Systems is not a function of the Balancing Authority. Requirement R11 can be removed. Should M11 use the same examples of evidence as does M10, for example Energy Management System description documents? M12 should have a broader scope. If the auditor is to verify that the TOP did not operate outside IROL for a duration exceeding IROL TV, then the TOP should provide information on all occasions in which he operated outside IROL for any period of time. This would reflect the RSAW's audit approach. M12 should read: "Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL Tv. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the

Organization	Yes or No	Question 1 Comment
		Transmission Operator may provide an attestation that an event has not occurred.” For IROLs there is a maximum exceedance duration specified, but for SOLs in R14/M14 there is no leeway. Thus if a SOL is exceeded for 30 seconds, the TOP must have evidence it initiated its Operating Plan. This applies also for the VSL in the Table of Compliance Elements. No difference is made if the TOP initiates its Plan within the minute or after half an hour. Entities generally have very many SOL exceedances a year and to document each of them a proof of Implementation of a Plan is unrealistic. Whereas IROLs may be more severe than SOLs, the measure is less stringent. In the C. Compliance section, under 1.3 Data Retention, Measure M14 is mentioned in the second and third paragraphs giving it two different data retention periods. There is a typing error in the fourth paragraph referring to R13/M13: “Each TOP shall each keep data (...)”. Remove the second “each”. In the Table of Compliance Elements there is a typing error in the last paragraph for Severe VSL listing for R8: “or more than 15%”. For R9, replace “and” with “or” because generally only one of the elements will be outaged. The VSLs should be revised to read “...sustained outage of telemetering or control equipment, or monitoring or assessment capabilities, or associated communication channels.” R10 and R11 should have similar VSLs. Presently if the TOP does not monitor a facility, it will be a Moderate VSL but if the BA does not monitor a facility, it is a severe VSL. Everything is lumped together for the BA whereas in reality it is not an all or nothing situation. R11 should therefore have VSLs equivalent to those in R10.

Organization	Yes or No	Question 1 Comment
		R14 should have different VSLs depending on the time it took the TOP to initiate its Operating Plan. R15 should have different VSLs depending on the time it took the TOP to inform its RC. Requirement R15 appears to be past tense, ' inform.. RC of actions taken...'. So one would believe that a pre-call is not required before actions are taken by the TOP. What is the purpose of this requirement? What is the added value in informing the RC after the fact of the actions that were taken to mitigate SOL exceedances? The TOP should be obligated to notify the RC if it cannot manage the exceedance on its own and needs assistance (another requirement). However, notifications via SCADA should be sufficient to address the concern. M15 - This measure does not include multi-modal communications. The TOP should be able to take credit for telemetered information (breaker operations) that communicates to the RC actions that have been taken. Also there is no time component for when to report. For example during, 5 minutes after, a day after. The word "own" should not be deleted from Requirement R16. It provides clarity that this is only pertaining to the equipment the Transmission Operator owns and not other equipment. The new requirement R19 addresses the data exchange capabilities needed. If non-BES facilities are to be included anywhere in the standard, they should be included in the BES by exception, especially since they are contributing to a SOL exceedance. R19 and R20 seem redundant with R10 and R11 since in R10 and R11 the TOP and BA are monitoring reliability required data, and they must have the data exchange capabilities. Also, TOP-003-3 requires the TOP to develop data specifications to support Real-time monitoring and operation of the

Organization	Yes or No	Question 1 Comment
		BES, and negotiate with data supplying entities the format, period and security protocol of the data exchange. This implies the requirement of a data exchange capability. We suggest removing R19 and R20. What defines a neighboring Transmission Operator Area? There are many instances where the loss of a facility in, let's say in Transmission Operator Area "A", which is not electrically "adjacent" to Transmission Operator Area "B", impacts Transmission Operator Area "B".

Response: The SDT agrees and has replaced 'address' with 'maintain' as suggested by you and other commenters. See summary for language.

The SDT disagrees. Same-Day Operations is a legitimate time horizon when considering actions to maintain BES reliability. No change made.

The SDT agrees and has replaced 'ensure' with 'maintain' in Measure M1.

Since no change was made to the time horizons in Requirements R1 and R2, there is no change applicable to Requirement R3.

The SDT believes that approved EOP-008-1, Requirement R1, Part 1.5 deals with restoring functionality, allowing for a 2-hour time period to handle transitions from primary to backup functionality. Approved EOP-008-1, Requirement R1, Part 1.6.2 deals with what needs to happen during that transition. That requirement states that an entity is still responsible for managing the risk during transition. The SDT believes that ensuring that a Real-time Assessment is performed at least once every 30 minutes is in agreement with the principle espoused in approved EOP-008-1 and is not unrealistic or overly burdensome in today's operating environment. This is also consistent with approved IRO-008-1, Requirement R2. No change made.

The SDT agrees and has added the term. See summary for language.

Requirement R10, Part 10.2 is nested within the main body of Requirement R10. Everything that comes after the main body of Requirement R10 refers back to the subject of Requirement R10. Therefore the Transmission Operator cited in Requirement R10, Part 10.2 refers back to the original subject Transmission Operator.

The SDT agrees and has made the suggested change. See summary for language.

Organization	Yes or No	Question 1 Comment
The language in Requirement R10, Parts 10.1.3 and 10.2.3 is consistent. Part 10.1.3 specifically contains the phrase 'as necessary by the Transmission Operator' because Parts 10.1.1 and 10.1.2 do not have this constraint. That specific language is not needed in Part 10.2.3 because the language in Part 10.2 already states that condition as it applies to all 3 sub-parts. No change made. The SDT believes that 'ensure' is the correct terminology in Requirement R13. The intent of the SDT is that the entity must make certain that someone, itself or another designated entity, is performing the Real-time Assessment as specified. "Ensure' is the proper connotation for those actions. No change made. The SDT agrees and has capitalized the term. See summary for language. The SDT agrees and has made the suggested changes for consistency. See summary for language. The SDT agrees and has changed Measure M7 as suggested. See summary for language. The SDT agrees and has changed Measure M8 as suggested. See summary for language. The SDT believes that knowledge of Special Protection Systems that impact generations is incumbent for the Balancing Authority. Item 19 of the Balancing Authority Functional Entity description in Functional Model v5 states: "Receives Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators." The SDT believes that this may include the status of Special Protection Systems that impact generation. Special Protection Systems could result in the tripping of multiple generation facilities, which may impact the Balancing Authority reserve requirements. No change made. The SDT agrees and has changed Measure M11 as suggested. See summary for language. The SDT agrees and has changed measure M12 as suggested. See summary for language. The SDT believes that the assertion that there is no leeway for an SOL exceedance is incorrect. The SDT would agree that there is no leeway for an SOL violation but there are different response times based on the type of SOL Exceedance that has occurred. SOL's are defined by the Reliability Coordinator and specific operator actions to mitigate SOL exceedances would be defined in that entity's Operating Plan. An SOL Exceedance is further described in the SOL Exceedance White Paper. Please refer to the SOL White Paper for additional details. No action required. The SDT agrees. The first instance of Measure M14 is incorrect and this error has been corrected. The SDT agrees and has removed the second instance of 'each' as suggested. The SDT agrees and has made the suggested correction to the Severe VSL.		

Organization	Yes or No	Question 1 Comment
The SDT has replaced 'and' with 'or' in the Requirement R9 VSLs. The SDT agrees and has changed the Requirement R11 VSLs accordingly. The SDT disagrees as it believes that the Operating Plan initiation is a binary action. Waiting to initiate the plan is dangerous and such actions should not be tolerated. No change made. The SDT believes that it is counter to reliability to place a time tag on informing the Reliability Coordinator. The operator should be concentrating on the reliability issue and not be concerned with adhering to an arbitrary time period for informing entities. Since no time frame is deemed appropriate for the requirement itself, the SDT does not believe that time periods should be introduced in the VSLs. No change made. Requirement R15 is intentionally written in the past tense as it is feedback to the Reliability Coordinator after the fact. The Transmission Operator has primary responsibility for mitigating SOL exceedances. Pre-calls to a Reliability Coordinator are not ruled out by this standard and can take place at the discretion of the Transmission Operator if it believes they are necessary or if prior agreements between the Reliability Coordinator and Transmission Operator dictate such an action. Regardless, the SDT believes that it is an important for BES reliability for the Reliability Coordinator to know what actions were taken to mitigate the situation. How such notification is made is up to the entities involved as 'how' is not within scope of standards. If two entities agree that SCADA provides sufficient notification that is an acceptable method of notification. Nothing in this requirement or standard precludes that. No change made. Measure M15 is not a hard and fast listing of every method that can be used to impart the required information. The language states 'such as' so that there is some degree of flexibility in how to comply with the requirement. The SDT believes that telemetering data/information could be an acceptable method. The SDT can't introduce timing requirements in a measure if they are not cited specifically in the requirement. The SDT did not place timing requirements in the standards because the SDT believes that such inclusion could be detrimental to reliability as it would force a Transmission Operator to focus on how quickly to perform this task as opposed to concentrating on alleviating the reliability concern. No change made. 'Own' was removed due to multiple industry comments in a previous posting. The SDT agreed with the comments stating that the term was redundant. No change made. Requirement R19 does not directly address the concept of non-BES facilities. However, when that topic does occur the SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES		

Organization	Yes or No	Question 1 Comment
Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology. See summary for language. Reliability Standards must include explicit requirements and can't make assumptions as to things being in place in order to be able to comply with a particular requirement. All requirements must be spelled out and applied as needed. This was made clear in the FERC NOPR delivered in response to the Project 2006-06 and 2007-03 filings. No change made. Due to your comment and others, 'neighboring' is no longer used in this standard.		
BC Hydro	No	BC Hydro's concern is that the Reliability Directive is replaced with Operating Instruction in the standard. The scope of "Operating Instructions" broadens to non-emergency situations. Requirement R3 and R4 have the BA's complying with TOP's Operating Instructions. BC Hydro's concern is that there may be a conflict between the BA and the TOP. Requirement R3 provides exceptions for complying, but only for safety, equipment regulatory or statutory requirements. Nowhere does the Requirement address conflict in reliability requirements: for example, a TOP in our area issues an instruction to eliminate a voltage limit issue, and this action may cause another limits issue for another TOP. There appears to be no "out" clause based on reliability conflicts - such as deferring to an assessed lesser reliability impact. BC Hydro recommends revising these Requirements to allow for an "out" clause.
Response: 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. No change made. The standards have been set up so that the Transmission Operator determines SOLs and is the primary responsible entity for them. However, the Reliability Coordinator still maintains an obligation to monitor SOLs. This means that the Reliability Coordinator will be		

Organization	Yes or No	Question 1 Comment
able to apply its wide-are view on actions taking place and will step in as needed if actions are causing other problems that a specific Transmission Operator is unable to ascertain. No change made.		
PacifiCorp	No	Definition of Real-Time Assessment contains provisions that will make compliance with the Requirements unattainable. First, the applicable inputs to the assessment include among other things, "known Protection System status or degradation." Real time tools are generally incapable of consideration of the performance of protection systems, and accordingly conducting these assessments prescribed in the Requirements will fall short of the expectation.
Response: The SDT recognizes that Real-Time Assessments may not automatically include "known Protection System status or degradation". However, once the issue is communicated to the Transmission Operator, the Transmission Operator has the capability to determine if Contingency definitions need to be modified and analyze the impact of such changes. No change made.		
Bureau of Reclamation	No	First, Reclamation continues to disagree with the use of the term Operating Instruction in TOP-001-3 R1-R6 and the entire TOP/IRO Revisions. 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. During normal operations, Reclamation does not believe that Transmission Operators should be able to always issue mandatory Operating Instructions to generators that may damage critical generating equipment or interfere with competing obligations (e.g., water delivery schedules for hydroelectric producers). Reclamation disagrees with the drafting team's assertion that "the definition for Reliability Directive is not needed due to work ... on the definition of Operating Instruction." Reclamation believes that additional conversations with FERC may be necessary, and that TOP-001-3 should maintain the important concept that Balancing Authority and Transmission

Organization	Yes or No	Question 1 Comment
		Operators only may issue Reliability Directives to address Emergencies or avoid Adverse Reliability Impacts. Reclamation also believes that Balancing Authorities and Transmission Providers should be required to inform entities when they are issuing a Reliability Directive. In some instances, Balancing Authorities and Transmission Providers have decided after the fact that an instruction was a Reliability Directive. Reclamation does not believe that the requirements to comply with Reliability Directives in TOP-001 and IRO-001 should be invoked if an entity does not describe the instruction as a Reliability Directive. Second, Reclamation also continues to disagree with the drafting team's proposal to revise TOP-003-3 to require Generator Owners, Generator Operators, and Transmission Owners to meet any data specification outlined by Transmission Operators or Balancing Authorities. Like TOP-003-1, TOP-003-3 should outline a specific continent-wide standard like the submission of planned generation outages over 50MW by noon on the day before the outage, a requirement that has existed for 7 years. Reclamation does not support TOP-003-3 because it does not clearly define what types of data entities can request or may be required to provide, and will create significant operational challenges for entities operating in multiple Transmission Operator and Balancing Authority areas. As an example, Reclamation owns and operates over 50 hydroelectric facilities in seven control areas and this change would prevent Reclamation from adopting a uniform approach to demonstrating compliance with TOP-003. Under the current version of TOP-003, Reclamation can present a uniform approach to demonstrating that it submits planned outages before noon the day before the outage. In fact, like many generation entities, Reclamation generally submits planned outages more than a year in advance and plans non-routine outages as far in advance as practical. Under the proposed version of TOP-003-3, Reclamation would have to track and adjust individual generator Standard Operating Procedures (SOPs) to meet different and

Organization	Yes or No	Question 1 Comment
		perhaps ever changing data specifications developed by each Transmission Operators, which could result in high costs for little reliability benefit.
Response: 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). Requirements R3 and R4 define provisions under which Balancing Authorities, Generator Operators, and Distribution Providers are not obligated to follow Operating Instructions issued by the Transmission Operator. No change made. Proposed TOP-003-3 was approved by the industry and is not a part of this current proceeding.		
Con Edison, Inc.	No	Requirement R13 is problematic. The 30 minute requirement in R13 is too restrictive and inconsistent with EOP-008, which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be granted the same time consideration to restore real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13: o Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every two hours. o Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every 30 minutes when the EMS & SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform real-time assessments within two hours. Requirement R7 raises jurisdictional concerns. We recommend the following change to R7 to target the TOP's requirement to assist other TOPs to those in the same RC area: R7. Each Transmission Operator shall assist other Transmission Operators within their Reliability Coordinator's region, if requested and able, provided that the requesting entity has implemented

Organization	Yes or No	Question 1 Comment
		its Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
Response: The SDT believes that approved EOP-008-1, Requirement R1, Part 1.5 deals with restoring functionality, allowing for a 2-hour time period to handle transitions from primary to backup functionality. Approved EOP-008-1, Requirement R1, Part 1.6.2 deals with what needs to happen during that transition. That requirement states that an entity is still responsible for managing the risk during transition. The SDT believes that ensuring that a Real-time Assessment is performed at least once every 30 minutes is in agreement with the principle espoused in approved EOP-008-1 and is not unrealistic or overly burdensome in today's operating environment. One option is to have an Operating Procedure which has the Reliability Coordinator perform the Real-time Assessment on behalf of the Transmission Operator under an EOP-008 scenario. This is also consistent with approved IRO-008-1, Requirement R2. No change made. The SDT agrees and has made the suggested change. Any request for assistance from Transmission Operator A to Transmission Operator B in another Reliability Coordinator Area would be coordinated with its respective Reliability Coordinators to assure a wide-area view is being applied to the situation. See summary for language.		
MRO NERC Standards Review Forum	No	R1 and R2 are ALL encompassing actions that cover every actionable NERC Requirement that the TOP and BA must accomplish. As written, "Each (BA, TOP) shall act to address the reliability of its (BA, TOP) Area via direct actions or by issuing Operating Instructions". EOP-002-3.1, R6, IRO-001-1.1, R8, are two examples where there must be "immediate" actions by the BA or TOP. If "via direct actions" is maintained in this proposed Standard, there will be a non-compliance double jeopardy impact if the BA or TOP violates an "immediate action" Requirement. Is the intent of R1 and R2 to issue Operating Instructions when the BA or TOP cannot maintain a reliability of their associated area? The NSRF wishes to points out that the 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

Organization	Yes or No	Question 1 Comment
		achieve a specific reliability objective and not how that objective is achieved". R1 & R2 with their broad, general language do not meet the threshold for a "Results Based Requirement". The NSRF agrees with issuing Operating Instructions when required to maintain your system in a reliable state. But the all-encompassing "via direct actions", is applicable to over 460 Requirements that a BA must comply with. How is this going to be measured for the BA (or TOP)? Are voltage schedules going to be measured when that is covered in the VAR Standards? Is seems to be a catch all Requirement. A possible rewrite of R1 and R2 could read: "Each (BA, TOP) shall issue Operating Instructions to address the reliability of its area when direct actions require more assistance ". M1 does not reflect the current language of the rewritten R1. The word "ensure" still resides in M1. R9. Concerning "sustained outages", is there a minimum reporting threshold for this undefined term? EOP-004-2, Event Type "Complete loss of voice communication capability" and "Complete loss of monitoring capability" has a 30 minute continuous threshold. The NSRF recommends using the same bright line criteria of EOP-004-2 as stated above. R13. Real-time Assessment: The NSRF still has concerns about how entities will incorporate "protection system status" into their real-time 30 minute assessment to be fully compliant. More clarity is needed for entities to verify that they have met the requirement. How are entities expected to show that their operators are aware of protection system status (as defined in the proposed Real-Time Assessment definition) and understand the system impact if a protection system is out-of-service? If policies, procedures, and snapshots of system operator tools are sufficient, this can be done. However, large scale state estimator real-time contingency assessments used have limitations. State estimators run DC power flows based on programed line and node based contingencies. Protection system

Organization	Yes or No	Question 1 Comment
		status changes that modify the lines and nodes studied may not be easily incorporated into state estimator systems in 30 minutes. Protection system coverage could easily change for known and unknown conditions. Known changes can include PRC testing. The PRC testing standards have mandated large amounts of testing for even moderately sized system so that daily testing must occur to meet mandatory testing timeframes. The large volume of PRC testing could make accounting for all protection system status changes within 30 minutes difficult to verify and puts entities at risk for maintaining perfect compliance to a large number of requirements since many of the TOP / IROL standards include the real-time assessment definition. Recommend that “protection system status” be deleted from the definition or at a minimum clarify that protection system status consideration by system operations is acceptable to be compliant, since “status consideration” equates to “situational awareness”. As written in R13:R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. [Violation Risk Factor: High] [Time Horizon: Real-time Operations] 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. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence. 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.”

Organization	Yes or No	Question 1 Comment
		Measure M13 would need commensurate edits to conform with this R13 language. Entities have made these comments before and the SDT did not agree as they said; The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made. The first concern is the NSRF believes that without further clarification, System Operators will not have the "situational awareness" because they will not know "known Protection System and Special Protection System status or degradation..." per the Real-time Assessment definition, thus will most likely be non-compliant on a daily basis. A 4000 breaker Transmission system can have up to 20,000 (4000 x 5 parts of a Protection System) parts that would need to be tracked every 30 minutes. This is unrealistic and not physically possible. The SDT continues to use the words "have situational awareness" in their response to comments, and that the Requirement is not about an RTCA. But without using the RTCA, how will the System Operator prevent instability, uncontrolled separation or Cascading outages, per the Purpose of this proposed Standard? The Real-time assessment must consist of existing and potential operating conditions, per the definition. A System Operator cannot calculate all the minimum inputs every 30 minutes without using some type of calculating device. Please review the below violation which is based on Auditor notes (for TOP-002-2, R11). This shows that simple "situational awareness" is predicated on "system analysis", which the NSRF looks at as the entities RTCA. A second concern with the TOP-001-

Organization	Yes or No	Question 1 Comment
		3 definition of Real time assessment, the recent TOP-002-2.1b R11 auditor guidance in the new RSAW, and a recent TOP-002-2.1b R11 violation cited below, is the proposed requirement is not technically feasible today. The three items listed just above in conjunction require an on-line dynamic stability assessment tool that can run multiple AC dynamic angular and voltage stability assessments in less than 30 minutes considering EMS input of the most recent alarm, SPS, and degraded state alarm statuses. The NSRF isn't aware of RTCA technology that can meet these requirements. Alternately, the assessment falls to human manpower to perform these studies. Entities must identify a RTO, RC, or PA with staff available 24/7 to perform this or train its own 24/7 staff. It takes time to train dynamic stability staff and time to change the model to capture "known Protection System" statuses.TOP-001-3 Definition: 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, known Protection System and Special Protection System status or degradation, 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.)TOP-002-2.1b violation: (note this is publically posted in the most recent November compliance and enforcement spreadsheet) TOP-002-2.1b R11. On two occasions, SCS-Trans' updated Bulk Electric System (BES) studies failed to reflect current system conditions. Specifically, two unscheduled outages of Protection System components, one for a 500 kV transmission line and one for a 230 kV transmission line, were not considered in SCS-Trans' operating studies. TOP-002-2.1b RSAW auditor Guidance: Evaluation of Protection System Outages Protection Systems must operate and clear faults within the required clearing time to satisfy system performance requirements. All outages of

Organization	Yes or No	Question 1 Comment
		Protection Systems or their components that affect the reliability performance of the transmission system must be evaluated for the periods they are scheduled, in the planning horizon in TPL assessments and in the operational planning timeframe through operating studies. For example, if a transmission line has A and B protection packages that are not functionally equivalent and the outage of one protection package affects the operating speed of the Protection System, the impact of slower fault clearing on the power delivery capability of the Bulk Power System (BPS) must be considered in the assessments and studies. Such impacts also must be considered when a transmission line has a single protection package and one component of the package (e.g., the communication system) is taken out of service

Response: 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. Specific actions for specific situations will be covered under the applicable standards. The wording of the requirements has been changed to provide additional clarity. See summary for changes.

Measure M1 has been corrected.

The SDT agrees and has made the suggested change. See summary for language.

The SDT recognizes that Real-Time Assessments may not automatically include “known Protection System status or degradation”. However, once the issue is communicated to the Transmission Operator, the Transmission Operator has the capability to determine if Contingency definitions need to be modified and analyze the impact of such changes. No change made.

The suggested language change to Requirement R13 presents ambiguity and is not measurable. No change made.

As there was no change to Requirement R13, there is no need for a corresponding change to Measure M13.

The SDT recognizes that Real-Time Assessments may not automatically include “known Protection System status or degradation”. The SDT also recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. However, once the issue is communicated to the Transmission Operator, the Transmission Operator

Organization	Yes or No	Question 1 Comment
has the capability to determine if Contingency definitions need to be modified and analyze the impact of such changes. No change made.		
Oklahoma Gas & Electric SPP Standards Review Group	No	M1 - Replace 'ensure' with 'address' as in the requirement. R8 - With the removal of 'other' when referring to 'known impacted Transmission Operators' an overzealous auditor could require a Transmission Operator experiencing a condition which could be an Emergency or result in an Emergency would have to inform itself. Using 'other known impacted Transmission Operators' eliminates this situation. We recommend the drafting team return 'other', in the suggested location, to the requirement, measure and VSLs. R8 VSLs - If the drafting team decides not to make this suggested change, the term 'other' needs to be removed from the first 'OR' in the Severe VSL. In the last 'OR' of the Severe VSL insert the phrase '..., whichever is greater,...' between 'Authorities' and 'of'. R9 - We appreciate the drafting team attempting to add specificity to Requirement R9; however, 'sustained' is undefined. How does a Transmission Operator determine whether or not they are compliant with this requirement? What ensures auditors will consistently apply the terminology. We recommend the drafting team incorporate language consistent with COM-001-2, R10 which requires notification for outages lasting 30 minutes or more. If 30 minutes is determined to be too long, reduce the time to 15 minutes. We would like to suggest adding the term 'known' in front of 'impacted' in the second line of Requirement R9. We would like for the drafting team to help provide some clarity in Requirement R9..... does it apply to Planned Outages? Also, we noticed that the term 'planned' was removed from Measurement M9. Our question to the drafting team was this your intent to remove this term and if so would

Organization	Yes or No	Question 1 Comment
		you provide clarity on why the term should be removed. We would like to suggest that the drafting team tie Requirement R9 to the Data Specifications of TOP-003-3 as suggested in the Mapping Document. Also, we would like to thank the drafting team for their willingness to adjust to many suggestions that are submitted and we truly appreciative for all or your time and efforts. R9 VSLs - Delete the phrase 'NERC registered' and insert the phrase '..., whichever is greater,...' between 'entities' and 'of' in the 'OR' of the Severe VSL. R10 VSL - The drafting team should consider adding a 2nd 'OR' to the High VSL which states 'The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1 and one of the items listed in Requirement R10, Part 10.2.' R16 - We would like for the drafting team to provide more clarity on the word "telecommunication". The word "telecommunication" should apply only to specific outages or maintenance work done on the SCADA/EMS that affect the System Operators. R19 & R20 Moderate and High VSLs - Replace 'entity' with 'entities'.

Response: Measure M1 has been corrected.

The SDT removed 'other' due to multiple industry requests in a previous posting. The SDT agreed with the commenters that the term was redundant. The SDT believes that the situation cited where an entity would have to inform itself is not realistic and not indicative of actual operations. No change made.

The SDT agrees and has made the suggested correction to the Requirement R8 Severe VSL.

The SDT agrees and has made the suggested change. See summary for language.

Requirement R9 does apply to planned outages and the SDT has revised the language to provide clarity on the topic. See summary for language.

Organization	Yes or No	Question 1 Comment
The SDT agrees and has made the suggested change to the Requirement R9 Severe VSL. The SDT agrees and has made the suggested change to the High VSL for Requirement R10. The SDT has changed the language of the requirement to provide clarity. See summary for language. The SDT agrees and has made the suggested change to the Requirement R19 and R20 VSLs.		
Tennessee Valley Authority	No	TVA feels that requiring a TOP to monitor neighboring facilities that are non-BES to determine SOL violations should not be required (see R10., 10.2.3). If non-BES facilities are required for the reliable operation of the transmission system they should first be included into the BES by use of the Rules of Procedure exceptions process.
Response: The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.		
Colorado Springs Utilities	No	Thank you SDT members for all of your work, the following were our comments on the proposed standard language. We will be voting affirmative, but think comments below crucial the final modifications to the standard. 1. "Ensure" was removed from R1 and R2 but please also remove it from M1 and M2.2. 2. R3 - LSE needs to be removed as this function is soon to be retired. 3. With the new definition of RAS just voted on, it would be best to replace RAS with SPS as "SPS" is going away.

Organization	Yes or No	Question 1 Comment
		4. Please change “maintain” to address in R19/M19 and R20/M20. This has similar implications of “ensure.” Of course we should do all in our power to maintain and ensure the bulk electric system, but there will be situations (no matter how many standards are in place) where industry may not be able to ensure or maintain reliability. To use such language is putting an unrealistic expectation in place that gives the regulator the ability to use our own words to find fault, even when no fault is present.
Response: The SDT agrees and has corrected the measures. The SDT agrees that the Load-Serving Entity function may soon be deleted as the functions assigned to it are in the process of being retired or assigned to other functional entities. At its November 2014 meeting, the Board adopted the deletion of the Load-Serving Entity as a functional entity and a future filing with FERC will ask for approval of this action. Therefore, the SDT agrees to delete Load-Serving Entity from proposed TOP-001-3. See summary for language. However, there are two other standards in this project (Proposed TOP-003-3 and proposed IRO-010-2) that also contain the Load-Serving Entity as an applicable entity. Since those two standards have already passed ballot and been adopted by the Board, the SDT is not going to put the industry through the effort and burden of re-opening those standards at this time. When the retirement of Load-Serving Entity is adopted, there will be a project initiated to review all standards for the term and to make applicable deletions or replacements as needed. Those two standards will be picked up by that overarching project. Similar to the situation with Load-Serving Entity above, Remedial Action Scheme and Special Protection System are in the midst of a possible change. At its November 2014 meeting, the Board adopted this change and a future filing with FERC will ask for approval of this action. The best approach for this project on this issue at this time is to leave Special Protection System in place as it is used in multiple places throughout the project in approved standards and the SDT would like to retain consistency in terminology and to let the subsequent project make all changes applying to Special Protection System so that industry can see them all at one time. No change made. ‘Ensure’ does not appear in Requirements R19 or R20. No change made.		
JEA	No	For R4&5 the timing is vague. Should it be done immediately, within 30 minutes, etc.

Organization	Yes or No	Question 1 Comment
		For R9 we are concerned that "sustained" is vague. If it lasted 2 minutes, was that a sustained outage? R10 should only include BES elements. Items of concern can be added through the inclusion process. R13 should have an exclusion that allows procedures to be implemented when system information is unavailable to reduce the risk instead of simply requiring real-time assessments be performed at least every 30 minutes. Even having a complete redundant EMS system might not prove sufficient to prevent a violation. R19 & 20 should require other BAs and TOPs to participate.

Response: The SDT believes that the timing issue will take care of itself. If an entity can’t comply it is in its best interests to notify the Transmission Operator/Balancing Authority as soon as possible. Any attempt to mandate a specified time would be self-defeating and overly prescriptive and thus not in the best interest of BES reliability. No change made.

The SDT agrees and has changed the requirement accordingly. See summary for language.

The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term ‘Facilities’. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.

The SDT has not stated how Requirement R13 is implemented as ‘how’ to do something is outside scope for Reliability Standards. If an entity can devise a procedure to accomplish the stated goal of the requirement then such a procedure would be an acceptable mechanism. One option is to have an Operating Plan which has the Reliability Coordinator perform the Real-time Assessment on behalf of the Transmission Operator under an EOP-008 scenario. No change made.

Organization	Yes or No	Question 1 Comment
The SDT believes that only one entity can be ultimately held responsible for these types of requirements and has written Requirements R19 and R20 accordingly. The ‘other’ entities will need to fall in line as they will be in violation of proposed TOP-003-3, Requirement R5 if they do not. No change made.		
Duke Energy	No	General Comments: Duke Energy is concerned with the uncertainty surrounding the inclusion and/or exclusion of Load Serving Entity in various Standards Projects. This inconsistency among Standard Drafting Teams creates uncertainty in the industry as to the expectations of the LSE, or whether the LSE will even be a applicable function. A more consistent application of the LSE function in proposed NERC standards is needed. R1: Based upon the comments provided below, Duke Energy suggests that 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”. We believe the intent is for the TOP to “maintain” the reliability of the TOP Area by Issuing Operating Instructions. Duke Energy believes that by using the term “address” in the current draft, the standard would only be requiring an entity to identify the problem and take action without any stated goal or result. We feel that by using the term “maintain”, the standard would require the entity to identify the problem and maintain the reliability of its TOP Area. Lastly, Duke Energy has concerns with the use of the term “act” in R1 and R2. As currently worded, absent the TOP issuing an Operating Instruction, R1 states that the TOP shall “act”, in other words, do its job. If an entity fails to perform some action in an effort to maintain reliability in its Area, the entity would be in direct violation of this standard. In the event that an entity violated any other TOP standard, it could be argued that the entity failed to perform a certain “act”, which presents a possible double jeopardy situation wherein the failure to act, violating one standard could be construed as a violation of the proposed TOP-001-3. We suggest the use of the phrase “issue

Organization	Yes or No	Question 1 Comment
		Operating Instructions" eliminates the possibility of a double jeopardy situation. R2:Based upon the comments provided below, Duke Energy suggests that 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". We believe the intent is for the BA to maintain the reliability of its BA Area by Issuing Operating Instructions. Duke Energy believes that by using the term "address" in the current draft, the standard would only be requiring an entity to identify the problem and take action without any stated goal or result. We feel that by using the term "maintain", the standard would require the entity to identify the problem and maintain the reliability of its BA Area. Lastly, Duke Energy has concerns with the use of the term "act" in R1 and R2. As currently worded, absent the BA issuing an Operating Instruction, R2 states that the BA shall "act", in other words, do its job. If the BA fails to perform some action in an effort to maintain reliability in its Area, the entity would be in direct violation of this standard. In the event that an entity violated any other BA standard, it could be argued that the entity failed to perform a certain "act", which presents a possible double jeopardy situation wherein the failure to act, violating one standard could be construed as a violation of the proposed TOP-001-3. We suggest the use of the phrase "issue Operating Instructions" eliminates the possibility of a double jeopardy situation. R9:Duke Energy would like the SDT to clarify the time duration of a "sustained outage". It is unclear if an outage lasting longer than 10min, 20min, 30min, etc., would be considered a sustained outage. Was it the SDT's intent to allow entities the flexibility to define what constitutes a "sustained outage"?

Organization	Yes or No	Question 1 Comment
		SOL Exceedance document: (1) Duke Energy suggests replacing “Thermal Limit Exceeded” with “SOL Limit Exceeded” to provide clarity in the example given in Table 1. (2) Duke Energy does not believe that the System Operating Limit Definition and Exceedance Clarification document should be attached to the TOP-001-1 standard. Instead, we believe it should be a standalone guidance document for the industry. If this were to occur, Duke Energy would likely vote “Affirmative” for TOP-001-1 as written.

Response: The SDT agrees that the Load-Serving Entity function may soon be deleted as the functions assigned to it are in the process of being retired or assigned to other functional entities. At its November 2014 meeting, the Board adopted the deletion of the Load-Serving Entity as a functional entity and a future filing with FERC will ask for approval of this action. Therefore, the SDT agrees to delete Load-Serving Entity from proposed TOP-001-3. See summary for language. However, there are two other standards in this project (Proposed TOP-003-3 and proposed IRO-010-2) that also contain the Load-Serving Entity as an applicable entity. Since those two standards have already passed ballot and been adopted by the Board, the SDT is not going to put the industry through the effort and burden of re-opening those standards at this time. When the retirement of Load-Serving Entity is adopted, there will be a project initiated to review all standards for the term and to make applicable deletions or replacements as needed. Those two standards will be picked up by that overarching project.

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. Specific actions for specific situations will be covered under the applicable standards. The wording of the requirements has been changed to provide additional clarity. See summary for changes

The SDT agrees and has changed Requirement R9 accordingly. See summary for language.

The SDT agrees and has made the suggested change in the redlined version of the SOL Exceedance White Paper.

The SOL Exceedance White Paper will not be attached to the standard but will be posted to a separate accessible place on the NERC web site. The exact URL is not available at this time but will be shown in Section F in the final posting of the approved standard.

Organization	Yes or No	Question 1 Comment
ISO/RTO Council Standards Review Committee (SRC)	No	SRC members generally agrees with the modifications to TOP-001-3 with the following additional recommendations for clarity, consistency, and/or to eliminate redundancy: 1. In Requirement R1, it is recommended that “address” is ambiguous and should be revised to “maintain” or “preserve” and that “[V]ia direct actions or by issuing Operating Instructions” should be revised to state “by initiating direct actions or issuing Operating Instructions.” Also, the measure M1 should be revised for consistency. 2. Review of modifications to IRO-001-4, Requirements R1, R2, and R3 to ensure consistency with the proposed revisions to TOP-001-3, Requirements R1 - R6.3. Requirement R7 has not retained an important concept contained within the previous requirement (TOP-001-1a - R6), which is that a supporting TOP should not be obligated to activate emergency procedures beyond those activated by the TOP that is in the emergency. As an example, the supporting TOP should not be obligated to go into voltage reduction if the TOP with the emergency has not taken the same voltage reduction action first. Hence, the phrase ‘... has implemented its Emergency procedures,’ is less specific than the previous standard and should be revised to provide ‘... has implemented its comparable Emergency procedures.’ 4. Requirement 10 seems duplicative in function with IRO-003, which requires the RC to monitor facilities associated with System Operating Limits (SOLs) and represents an overlap of the RC’s responsibility with the TOP draft requirement. Specifically, the TOP would have a requirement to monitor facilities outside of its TOP area that could affect SOL exceedances within its TOP area when the RC is already tasked with the “wide-area” view. This is in direct conflict with the Functional Model definition of a TOP which limits TOP responsibility to assets within its area.

Organization	Yes or No	Question 1 Comment
		Further, it is recommended that the term “non-BES” Be removed from Requirement R10. The “inclusion” process should capture all equipment that are sub-100 kV, but that affect BES reliability and bring this equipment into scope. Finally, in Requirement R10.2, the phrase ‘... as necessary by the TOP’ is unclear and should be redrafted to be consistent with 10.1 “10.2. In the neighboring Transmission Operator Area.” Conforming changes should also be made to Requirements R10.1.3 and 10.2.3. NOTE: this comment is not supported by PJM 5. The SRC appreciates the SDT’s effort to clarify the obligations of Balancing Authorities under Requirement R11. However, it respectfully submits that “in order to be able to perform its reliability functions” may still be ambiguous, resulting in subjective determinations of compliance. Additional revision is proposed to mitigate this ambiguity and to ensure that the reliability functions being referenced are clear: ”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-generation balance within its Balancing Authority Area, and support Interconnection frequency in real-time.” 6. The SRC respectfully submits that R15 is not necessary to ensure an Adequate Level of Reliability. Specifically, since the exceedance would have already been addressed or is being actively managed by the TOP and communication would already be occurring with impacted parties pursuant to other requirements, a requirement to inform the RC isn’t needed. If R15 is maintained, the SRC suggests including SCADA information in the Measurement so that the TOP can “inform” the RC through this mechanism. NOTE: this comment is not supported by PJM 7. The SRC reiterates it serious concerns over the proposed retirement of Requirement R4 of TOP-004-2 without requirements in TOP-001-3

Organization	Yes or No	Question 1 Comment
		addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unstudied state. In previous postings, the SRC expressed a concern that, by retiring R4 of TOP-004-2, the responsible entity (TOP in this case) will no longer be required to reconfirm or reestablish valid SOLs or IROLs when entering an unstudied state. We recognize that, by virtue of the proposed definition of Operational Planning Analysis (OPA) and Real-time Assessment (RTA), as well as the new requirement for TOPs to update their OPA results through the performance of a RTA every 30 minutes, entities will always be assessing the reliability of the BES. However, we continue to disagree with this rationale and provide additional information in response to the SDT's response to our last comment. In response to the SDT's indication that it does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL Tv, the SRC responds that an unknown state is one which has not been assessed before in IROL or SOL calculation or reliability assessment, and, therefore, there does not exist an updated, valid limit until it is re-determined (or reconfirmed). Thus, if an unknown operating state includes an unstudied state beyond those which the calculated SOLs or IROLs are intended to cover, then entities may find themselves in an unknown operating state. For example, in the Northeast, such as Quebec, Ontario and New York, SOLs/IROLs are observed to guard against transient or dynamic instability. These limits are normally developed using off-line analyses, as they cannot be determined within a short time using any on-line analysis tools available today. Predetermined reduction or judgment may need to be applied when system conditions, such as two or more critical facilities are out of service, diverge from the assumptions utilized in reliability assessment and other studies. In these circumstances, e.g., when an unstudied state is encountered, a necessary first step for the operating entities in these areas is to reconfirm or recalculate the limits that are valid and applicable for the prevailing

Organization	Yes or No	Question 1 Comment
		conditions. The reconfirmed or reestablished limits will become the target to which the system must be adjusted. Given the use of off-line studies to set limits and identify complex system conditions, the SRC believes that the OPA and RTA are good tools, but caution that these tools only look ahead at anticipated conditions and assess real-time situations in response to system changes. Accordingly, by themselves, they are not limit calculation mechanisms. Therefore, while these tasks will aid in assessing performance of the system against established limits, where such limits may not exist, the OPA and RTA are not the tools to calculate limits for the anticipated or prevailing conditions, especially for stability restricted SOLs/IROLs. To summarize, it is possible for the system to be in an unstudied or unknown state where established limits either don't apply or limits have not yet been established. While the RTA, OPA, and established Operating Plans can be quickly and easily applied to anticipated conditions, changes during real-time operation can render the assumptions and pre-determined limits invalid and, hence, the responsible entity cannot rely on these tools should these circumstances occur. Thus, the SRC once again urges the SDT to modify TOP-001-3 to expand Requirement R13 to require TOPs to reestablish valid SOLs when the prevailing conditions are beyond those that are covered by or have been studied in off-line calculations. NOTE: this comment is not supported by CAISO; ERCOT; MISO or PJM.

Response: 1. The SDT agrees and has made the suggested change. See summary for language.

The SDT agrees and has made the suggested change.

2. The SDT has reviewed the indicated requirements for consistency and believes that they are consistent. No change made.

The SDT agrees and has added the term. See summary for language.

4. The SDT does not believe that this requirement is duplicative. The SDT believes there is a distinction between 'identifying' (Reliability Coordinator task) versus 'determining' (Transmission Operator task). The Reliability Coordinator still retains responsibility

Organization	Yes or No	Question 1 Comment

for the ‘wide-area’ view – nothing the SDT has done affects that responsibility. However, Requirement R10 has been modified for clarification due to comments. See summary for language.

The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term ‘Facilities’. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.

The SDT used the phrase ‘as necessary by the Transmission Operator’ to allow the Transmission Operators maximum flexibility in deciding what data it needs. Every situation is different across the country. Any attempt to create a national standard stating exactly what data a Transmission Operator needs would be fraught with error when applied to all of the unique and specific configurations employed throughout North America. Therefore the language was crafted to recognize this fact and to place the onus of responsibility as to what is required on the individual Transmission Operator. No change made.

5. The SDT agrees and has made the suggested change. See summary for language.
6. The SDT believes that it is an important for BES reliability for the Reliability Coordinator to know what actions were taken to mitigate the situation. How such notification is made is up to the entities involved as ‘how’ is not within scope of standards. If two entities agree that SCADA provides sufficient notification that is an acceptable method of notification. Nothing in this requirement or standard precludes that. No change made.
7. 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. Furthermore, the standard does not prohibit an entity from performing an RTA more frequently in response to a unplanned system event. No change made.

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	(1) There are several issues with the draft standard of TOP-001-3. First, we disagree with the inclusion of the Load-Serving Entity (LSE) as an applicable entity. This function is being removed from the NERC Rules of Procedure and should not be included in the draft standard. TOP-001-3 already applies to the Distribution Provider (DP), so there will not be a gap in the future because LSEs are required to also be registered as DPs. We recommend removing the LSE from the applicability section for consistency with the revised NERC Rules of Procedure and to avoid a future standards project to correct this issue. In regards to timing, the NERC BOT will likely have approved removal of LSE before this is even approved in a final ballot by the ballot body. (2) Requirement R1 and Requirement R2 are problematic because they are vaguely written and could result in additional compliance burdens for a TOP or BA when there is an event. As currently written, any time that a TOP or BA has an outage there could be a violation because the entity did not address the reliability of its area. These requirements will be used in enforcement as additional fines without benefitting reliability because they do not state what actions should be taken. We also disagree with the High VRF and Severe VSL for these standards. These requirements are vague and need further refinement. (3) Requirements R3, R4, R5, and R6 should not apply to the LSE, as previously stated above. (4) Requirement R8 needs to be revised to remove the words “could result in an Emergency.” There are numerous situations that “could” result in an Emergency, but do not. This language is ambiguous and immeasurable, and should be removed. (5) Requirement R9 has improved with the addition of “sustained outages” to clarify that notification is not required for momentary events. However,

Organization	Yes or No	Question 1 Comment
		R9 is not clear as to the outage thresholds that would require a notification. When must the BA or TOP notify its RC? The requirement is ambiguous as written, which will lead to varying interpretations for compliance. This requirement needs to be revised to provide additional clarity when a notification to the RC is required. (6) Requirement R10 and part 10.1 are duplicative in listing "within its Transmission Operator Area." If taken as a whole, R10 states that "Each TOP shall monitor the following as necessary for determining SOL exceedances within its TOP Area: 10.1. Within its TOP Area: 10.1.1. Facilities..." This requirement needs to be revised to have proper sentence structure. (7) Part 10.3's reference to "Non-BES facilities" is outside the scope of reliability standards. Reliability standards are applicable to the BES, which would be Facilities. The revised BES definition addresses Elements and Facilities that should be subject to the reliability standards through the BES exception process. There is no reason to include non-BES Elements in the requirement. Parts 10.1.3 and 10.2.3 that reference "non-BES facilities" should be struck. (8) Thank you for the opportunity to comment.
Response: 1. The SDT agrees that the Load-Serving Entity function may soon be deleted as the functions assigned to it are in the process of being retired or assigned to other functional entities. At its November 2014 meeting, the Board adopted the deletion of the Load-Serving Entity as a functional entity and a future filing with FERC will ask for approval of this action. Therefore, the SDT agrees to delete Load-Serving Entity from proposed TOP-001-3. See summary for language. However, there are two other standards in this project (Proposed TOP-003-3 and proposed IRO-010-2) that also contain the Load-Serving Entity as an applicable entity. Since those two standards have already passed ballot and been adopted by the Board, the SDT is not going to put the industry through the effort and burden of re-opening those standards at this time. When the retirement of Load-Serving Entity is adopted, there will be a project initiated to review all standards for the term and to make applicable deletions or replacements as needed. Those two standards will be picked up by that overarching project.		

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<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">2. 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. Specific actions for specific situations will be covered under the applicable standards. The wording of the requirements has been changed to provide additional clarity. See summary for changes

3. The SDT agrees that the Load-Serving Entity function may soon be deleted as the functions assigned to it are in the process of being retired or assigned to other functional entities. At its November 2014 meeting, the Board adopted the deletion of the Load-Serving Entity as a functional entity and a future filing with FERC will ask for approval of this action. Therefore, the SDT agrees to delete Load-Serving Entity from proposed TOP-001-3. See summary for language. However, there are two other standards in this project (Proposed TOP-003-3 and proposed IRO-010-2) that also contain the Load-Serving Entity as an applicable entity. Since those two standards have already passed ballot and been adopted by the Board, the SDT is not going to put the industry through the effort and burden of re-opening those standards at this time. When the retirement of Load-Serving Entity is adopted, there will be a project initiated to review all standards for the term and to make applicable deletions or replacements as needed. Those two standards will be picked up by that overarching project.

4. The SDT believes that the language is correct as stated and consistent with the intent of the standards. If an entity performs an analysis and an Emergency situation is forecasted, then that entity should inform entities of this condition as per the requirement. An example could be the notification of an Emergency outage that would result in a known Stability issue requiring the execution of Operating Plans. No change made.

5. The SDT agrees and has made changes to the requirement. See summary for language.

6. The SDT disagrees. The first instance of ‘within its Transmission Operator Area’ refers specifically to the function of determining SOL exceedances. The second instance lays out what must be done within its own area to accomplish this task. No change made.

7. The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term ‘Facilities’. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.</td></tr>
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Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	No	BPA reiterates its comments from the previous period on TOP-001-3: BPA suggests referencing the System Operating Limit (SOL) Definition and Exceedance Clarification white paper in the language of the Requirements, as Regional Entities are not required to audit to appendices, unless indicated by the language of a Requirement. BPA believes the language in requirement R8 is still ambiguous and open-ended regarding, "... operations that result in, or could result in, an Emergency." It is unclear how entities are expected to determine events that could possibly happen. BPA suggests the drafting team include parameters for possible events, so applicable entities are not required to predict all possible future events. BPA also opposes language in the Standard which has the potential to conflate events that are happening with events that have a high probability of happening. BPA suggests the drafting team clearly separate these two concepts. Additionally, BPA disagrees with the change in R16 from "Real-Time Assessment" to "analysis". This is a very broad and, in this case, undefined term. BPA believes this could lead to differences in interpretation between a TOP and an auditor. For example, R16 applies to the Operations Planning Horizon. A study engineer's computer is part of an entity's analysis capability for doing studies in that horizon. Hence, as written, this requirement could be interpreted to mean that an entity's IT department would need to have System Operator approval prior to working on a study engineer's computer. BPA does not believe that was the drafting team's intent, but this broad language does leave that possible interpretation open.

Response: The definition of System Operating Limit is included in the NERC Glossary of Terms Used in Reliability Standards. By using the capitalized term, the requirements directly reference the defined term in the Glossary and are auditable. The SOL Exceedance White Paper is a guidance document and not intended to be part of a requirement. The paper outlines how the SDT interprets an

Organization	Yes or No	Question 1 Comment
SOL exceedance to be determined and what to do when such occurs. The SDT believes that entities will be audited to Standards and Requirements that are referenced within the White Paper. The intent of the White Paper is to assist in providing a common understanding across the industry. No change made. The SDT believes that the language is correct as stated and consistent with the intent of the standards. If an entity performs an analysis and an Emergency situation is forecasted, then that entity should inform entities of this condition as per the requirement. An example could be the notification of an Emergency outage that would result in a known Stability issue requiring the execution of Operating Plans. No change made. The SDT has revised the wording of the requirement to provide additional clarity. See summary for language.		
Hydro One	No	Requirement R10 presents a significant concern. A Transmission Operator cannot be held responsible for monitoring in a neighboring Transmission Operator Area; a Transmission Operator can only rely on data provided by a neighboring area. If a Transmission Operator was responsible for monitoring in a neighboring area, what is the TOP monitoring, how, what are the available actions and obligations, should the actions be taken unilaterally?
Response: The SDT is not implying that an entity needs to establish monitoring capabilities such as its own RTU in another Transmission Operator's Area. In this requirement, monitoring outside of the Transmission Operator's Area means that a Transmission Operator is obtaining the data and presenting it to its operators as needed. For example, the Transmission Operator would obtain the status and MW flow on external facilities that are identified as having an impact on the Transmission Operators System Operating Limits. To provide clarification on this matter, the SDT has restructured the language of the requirement. See summary for language.		
Owensboro Municipal Utilities	No	The current language in TOP-001 R1 and R2 has further expanded the applicable use of operating instructions encompassing all individuals to the point where the compliance risk of the requirement is not appropriately weighted with the benefit to reliability. R3 and R4 state that only the registered entities identified must comply with OI; they do not state that registered entities identified are the only entities that can receive OI.

Organization	Yes or No	Question 1 Comment
		Therefore, without the lack of specificity in R1 and R2 (or in R3 and R4) to whom OI can be issued to, the standard now requires three point communication to any party or entity for actions that will affect the BES, even though that entity (unless identified in R3 and R4) does not have to comply. Although the NERC functional model states to whom a BA and TOP can direct, this is not referenced or mentioned in the standard, and must be inferred by not only the entity maintaining compliance, but also the individual performing an audit. It would seem very beneficial to specify this assumption within R1 and R2. Suggested Wording: R1 and R2: "Each Transmission Operator (Balancing Authority) shall act, or direct others (referenced in R3 and R4) to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator (Balancing Authority) Area." In R10, replace "necessary" with "applicable" to maintain consistency with the definitions of Real-Time Assessment and Operational Planning Analysis. Suggested Wording: Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary applicable by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area In R13, the OC Review Group suggests expanding the time interval to 45 minutes instead of 30 minutes. When new EMS models are brought online, they may require greater than 30 minutes to perform an assessment. Either the time could be expanded or some sort of allowance provided for the times when the new models are being placed in service. In the R13 VSL, the OC Review Group suggests the time graduations for each level of VSL be retained (30-35 minutes, 30-40 minutes, 40-45 minutes, >45 minutes).

Organization	Yes or No	Question 1 Comment
		In R18, the OC Review Group suggests removing the word "always" before "operate" and provide graduated VSL to allow for when limits were determined to be incorrect due to mistake in entry of data. Suggested Wording: "R18: Each Transmission Operator and Balancing Authority shall always operate to the most limiting parameter in instances where there is a difference in SOLs." Should LSE be removed from applicable entities since LSE may be removed from the NERC Functional Model?

Response: The Functional Model is always implicitly part of any determination of how a requirement is written and is always a consideration in auditing a specific requirement. It is never explicitly cited in a requirement for those reasons. The SDT does not believe that the suggested change adds clarity or is necessary for reliability. No change made.

The SDT does not agree that 'necessary' should be replaced by 'applicable' in this requirement. The SDT believes that 'necessary' is the term that provides the proper context. No change made.

30 minutes is an approved time period for such requirements as seen in approved IRO-008-1, Requirement R2. The SDT has not received a preponderance of justification to change this previously approved time period. No change made.

The VSLs have been maintained.

The word 'always' is not used in Requirement R18. From reading the comment, it appears that the request is to add the term to the language. The SDT does not believe that this is necessary for reliability or that it provides any additional clarity. No change made.

The SDT believes that the VSL as currently stated is correct in its binary form. An entity should be operating to the most limiting set of limits with no exceptions. If the limits are incorrect, then an Operating Plan would be followed to adjust the limit until a new limit is analyzed and determined. No change made.

The SDT agrees that the Load-Serving Entity function may soon be deleted as the functions assigned to it are in the process of being retired or assigned to other functional entities. At its November 2014 meeting, the Board adopted the deletion of the Load-Serving Entity as a functional entity and a future filing with FERC will ask for approval of this action. Therefore, the SDT agrees to delete Load-Serving Entity from proposed TOP-001-3. See summary for language. However, there are two other standards in this project (Proposed TOP-003-3 and proposed IRO-010-2) that also contain the Load-Serving Entity as an applicable entity. Since those two standards have already passed ballot and been adopted by the Board, the SDT is not going to put the industry through the effort and

Organization	Yes or No	Question 1 Comment
burden of re-opening those standards at this time. When the retirement of Load-Serving Entity is adopted, there will be a project initiated to review all standards for the term and to make applicable deletions or replacements as needed. Those two standards will be picked up by that overarching project.		
Hydro-Quebec Production	No	Inclusion of NON-BES at R10 is inacceptable
New York State Department of Public Service	No	The requirement to monitor non-bulk facilities raises jurisdictional questions which needs to be settled before inclusion.
Response: The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.		
Flathead Electric Cooperative, Inc.	No	I continue to disagree with the level of detail in M3 and M4 for entities on the receiving end of a recorded instruction at the Transmission Operator/Balancing Authority level. Why should this have to be auditably demonstrated at both ends when everything is recorded upstream?
Response: The measures cited provide a list of things that could be supplied as evidence but there is no hard and fast requirement that voice recordings be supplied by both entities. An entity can make its own determination of whether it wants to maintain voice recordings or supply some other evidence for proof of compliance. No change made.		
Ameren	No	We have concerns on what constitutes "Operating Instructions", and over how an entity is supposed 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

Organization	Yes or No	Question 1 Comment
		TOP's to an very burdensome way of documenting compliance. 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. 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. 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 locate any such information in the Reliability Standard itself, nor does the standard give guidance on when there are no BES events for the period being audited.
Response: 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. No change made. The use of events in the RSAWs is designed to limit the scope of where an auditor should look for situations where these requirements may come into play. It should effectively reduce the amount of time where an auditor would be looking for evidence which should make an audit easier and more effective. In several locations, such as Measure M3, the SDT has addressed situations where no event may have occurred by allowing for attestations to that effect.		
NIPSCO	No	NIPSCO feels R19 and R20 should be in TOP-003 or are already covered in COM-001.

Organization	Yes or No	Question 1 Comment
		NIPSCO feels R16 and R17 are outage coordination and do not belong in TOP-001 which is Transmission Operations. These should be with the outage coordination standard.
Response: Approved COM-001-2 refers to voice communications and not data. Proposed TOP-003-3 defines operational reliability data specifications. FERC has made it clear in past transactions that data, in and of itself, is not sufficient for mandatory standards. There needs to be 'hardware' in place in order for the data to be exchanged and the SDT has written Requirements R19 and R20 accordingly. No change made. The proposed IRO-017-1 outage coordination standard is designed for Transmission and generation outages and coordination of same. Requirements R16 and R17 do not fit into that categorization and the SDT believes they are better suited to proposed TOP-001-3. No change made.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration L.P. ("ICLP") understands that FERC has ordered that TOPs and RCs must be able to monitor "non-BES" systems that they determine will affect System Operating Limits. However, it naturally follows that such important facilities must be part of the BES - and addressed in a far more formal way. It seems to ICLP that just such an exception process was created in NERC's Rules of Procedure when the Definition of the BES was modified. It allows the TOP/RC to make the case for the new addition - while the owner/operator has the opportunity to challenge it. Even if there needs to be an emergency bypass procedure to account for unexpected circumstances, at least a level of important control will exist. Otherwise, components and facilities can be essentially added to the BES without any recourse on the part of the affected entity. This raises the specter of the improper sharing of proprietary information and the chance of economic discrimination if such authority is misused. Secondly, a GOP will be expected to capture the fact that every Operating Instruction was performed unless it would "violate safety, equipment, regulatory, or statutory requirements." ICLP will execute in good faith to every instruction, but we are not confident that our log entries will be up to

Organization	Yes or No	Question 1 Comment
		auditor expectations - particularly if routine status or some other low-impact action is requested. The alternative offered by the project team (the RSAW only directs CEAs to review logs where a EOP-004-2 defined Event took place) is not binding. It is not hard to see that expectations will vary by Regional Entity and even change over time. Furthermore, the target of Operating Instructions will not be limited to BES Facilities. This could mean that as a Cogeneration Facility, we will be put into an untenable bind if ordered by a BA or TOP to re-direct capacity to the BES at the expense of our internal customer. Of course we are responsive to the needs of the greater system, but it should not be up to external entities to decide which needs take priority - keeping in mind that our installation is a critical part of the national chemical infrastructure.
Response: The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology. Given the guidance provided to the auditor in the proposed RSAWs, BES events will be used by the auditor to constrain the potential amount of data an entity will need to provide. The SDT believes that this guidance is being provided in good faith and with the view that it will be used on a national basis. No change made. Nothing in this proposed standard exposes non-BES facilities to any requirement in any standard. The only obligations with regard to non-BES facilities is for data as documented in proposed TOP-003-3. No change made.		
Puget Sound Energy	No	The drafting team's revisions significantly improve the proposed standard. However, requirements R3 and R5 continue to impose a high compliance burden on entities that receive Operating Instructions. For example, a

Organization	Yes or No	Question 1 Comment
		Generator Operator could receive thousands of dispatch instructions each year. As the term is defined, each of these dispatch instructions would be an Operating Instruction and the GOP would be required to demonstrate that it complied with each of these Operating Instructions (or that it was unable to comply for the reasons specified in requirements R4 and R6). The standards drafting team for COM-002 recognized this issue when it developed a tiered approach for the communication protocols associated with Operating Instructions. The first tier requires an entity to periodically monitor compliance with its communications protocols and then correct issues that are discovered during this monitoring. The second tier requires entities to comply fully with its communication protocols during Emergency conditions only. This approach recognizes the importance of formal communications during both normal and Emergency conditions, but appropriately minimizes the compliance burden that would be associated with demonstrating compliance with an entity's communication protocols for all Operating Instructions. The drafting team should model that approach in this standard.
Indiana Municipal Power Agency	No	Indiana Municipal Power Agency (IMPA) appreciates the hard work and effort the SDT has put into this standard. IMPA does not agree with using Operating Instructions within this standard. By using Operating Instructions within this standard, NERC has created an extremely administrative type of standard for entities to follow and to keep evidence to show they performed the Operating Instruction. This seems to be going in the opposite direction of what NERC is proposing in its RAI program with the theme of concentrating on the "risk" to the BES. IMPA acknowledges that the SDT writes the standard but also understands the influence NERC has on standard drafting teams. During high load times, an entity that has to follow its TOP's Operating Instructions will need to keep a good recording or log entry of the Operating Instruction and then proceed to keep documentation showing it was performed. Since the definition of an

Organization	Yes or No	Question 1 Comment
		Operating Instruction is vague and not clear, an entity will have to do this for every instruction from its TOP regardless of how they see the instruction because an auditor may view it as an Operating Instruction. For example, a Generator Operator will have to keep a log and evidence to show it performed the Operating Instruction for every start, stop, and load command for all of its generating units within its fleet (PJM is the TOP for many GOPs). IMPA recommends the drafting of requirements that allow entities to focus on the "risk" to the BES and not write requirements which are administrative in nature (meet paragraph 81 criteria).
Response: Given the guidance provided to the auditor in the proposed RSAWs, BES events will be used by the auditor to constrain the potential amount of data an entity will need to provide. The SDT believes that this guidance is being provided in good faith and with the view that it will be used on a national basis. No change made.		
ReliabilityFirst	No	ReliabilityFirst abstains and offers the following comment for consideration.1. Requirement R1, R2, R3 and R4 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. 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 it 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

Organization	Yes or No	Question 1 Comment
		cannot be performed].R4 - Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within the time constraints allocated by the Transmission Operator] of its inability to perform an Operating Instruction issued by its Transmission Operator...” R6 - Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within the time constraints allocated by the Balancing Authority] of its inability to perform an Operating Instruction issued by that Balancing Authority.”
Response: 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.		
Independent Electricity System Operator	No	We generally agree with the changes made to the proposed TOP-001-3 standard, but continue to have a serious concerns over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state. We strongly believe that the Requirement R4 of TOP-004-2 addresses a critical reliability aspect that ensures the bulk electric system is operated in a reliable manner during real-time operations. And, if is not actually replaced by any new or revised requirement in TOP-001-3, it will create a reliability gap that is critical to the reliable operation of the bulk electric system. Requirement R4 of TOP-004-2 stipulates that: 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. In previous postings, we expressed a concern that by retiring R4 of TOP-004-2, the responsible entity (TOP in this case) will no longer be

Organization	Yes or No	Question 1 Comment
		required to reconfirm or reestablish valid SOLs or IROLs when entering an unknown (or unstudied) state. We recognize that by virtue of the proposed definition of Operational Planning Analysis (OPA) and Real-time Assessment (RTA), as well as the new requirement for TOPs to update their OPA results through the performance of a RTA every 30 minutes, that the entities will always be assessing the reliability of the BES. The SDT thus argues that this, together with the TOP-001-3 Requirements R12, R13, and R14, will allow the operators sufficient flexibility within a structured environment to take the necessary actions for the reliability of the Bulk Power System and hence Requirement R4 of TOP-004-2 can be retired. We continue to disagree with the SDT's rationale for retiring R4 of TOP-001-3. Below is our point by point comment on the SDT's response to our last round of comment. This is not meant to be a criticism of the SDT's response. Rather, we choose to present our comment in this manner so that we can more clearly present our view on each of the technical arguments that the SDT made. a. The SDT [believes the existing requirements within the standard to perform a Real-time Assessment include reevaluation of SOL/IROL limits to either reestablish new limits or implement Operating Plans to stay within updated limits. The SDT does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL Tv.] The IESO believes that an unknown state is one which has not been assessed before in IROL or SOL calculation or reliability assessment, and therefore there does not exist an updated, valid limit until it is re-determined (or reconfirmed). We further believe that the SDT's view that "by complying with the proposed requirement, an entity will never enter into an unknown state" may be an oversimplified assumption, if not an oversight. An unknown operating state includes an unstudied state beyond those which the calculated SOLs or IROLs are intended to cover. b. [The premise of the SDT's philosophy is that an Operational Planning Analysis must be available for next day and that this analysis must be periodically

Organization	Yes or No	Question 1 Comment
		updated by performing a Real-time Assessment as per proposed TOP-001-4 Requirement R13.]The IESO believes that the OPA and RTA are good tolls, but they only look ahead at anticipated conditions and assess real-time situation in response to system changes and by themselves they are not a limit calculation mechanisms. Therefore, while these tasks will aid in assessing performance of the system against established limits, such limits may not exist; and OPA and RTA are not the tasks to calculate limits for the anticipated or prevailing conditions, especially for the stability restricted SOLs/IROLs. c. [Both of these functions require an established set of Facility Ratings be in use so that analysis can discern when these limits are being exceeded. It is the SDT's belief that once these limits have been established that it does not matter what event occurs to cause an exceedance.]The IESO believes that this may be true for facility limited SOLs/IROLs, but not for voltage and/or stability restricted SOLs/IROLs. d. [The event takes place and is analyzed against the set of limits currently in place.]The IESO believes that a set of valid limit (voltage and stability limited type) may not exist for conditions that have not been studied and therefore there is no such "set of limits currently in place". e. [It is these limits that an entity must restore the system to following the event as per proposed TOP-001-4 Requirement R14.]This is achievable if the limits already exist. But when the limits do not exist, as in the case of SOLs or IROLs that are restricted by stability and when the prevailing conditions are ones that have not been studied before, there is not a target (SOL or IROL) with which the system is to be restored to. f. [Therefore, the SDT believes that approved TOP-004-2 Requirement R4 can be retired without creating a reliability gap. The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. No change made. The IESO believes that an Operating Plan is only a plan for the anticipated conditions. Changes during real-time operation can render the assumptions and pre-determined limits invalid and hence the responsible

Organization	Yes or No	Question 1 Comment
		entity cannot rely on the Operating Plan to provide SOLs/IROLs that are stability restricted. We agree that with the current technology, it is doubtful if any entities can rely on real-time tools to calculate SOLs/IROLs in 30 minutes. However, this should not be a reason to not reestablish SOLs/IROLs when an entity encounters a condition that is "unknown" or not studied before. There are various means to achieve such tasks, but a necessary first step to ensure entities reestablish valid SOLs/IROLs is to stipulate this in a standard. Retiring R4 of TOP-004-2 will do just the opposite: responsible entities will not be mandated to reestablish valid limits to begin with when entering an unstudied or unknown state. We once again urge the SDT to reinsert R4 of TOP-004-2 to TOP-001-3, or to expand Requirement R13 to require TOPs to reestablish valid SOLs when the prevailing conditions are beyond those that are covered by or have been studied in SOL calculations.
Response: 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. Furthermore the standard does not prohibit an entity from performing an RTA more frequently in response to a unplanned system event. No change made.		
NV Energy	No	The comments of NV Energy, particularly with regard to requirement R13, remain unaddressed in this latest posting. We continue to urge the SDT to depart from the zero defect approach on the language of R13. It seems unreasonable to expect perfect execution of the suggested real-time analyses, including the provisions for incorporation of the elements of SPS/RAS and protection system status, 17,520 times per year. By the SDT's

Organization	Yes or No	Question 1 Comment
		own response to NV Energy's comments in the prior ballot/comment period " This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times." Yet the SDT nevertheless declined to make any change to the language of R13. We continue to believe that the language suggested below is reasonable given the complexity of the requirements of TOP-001-3. We therefore suggest the following: 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."
Response: The SDT has reviewed the suggested language change to Requirement R13 and concluded that the proposal presents ambiguity and is not measurable. Proposed IRO-008-1, Requirement R2 currently requires the Reliability Coordinator to conduct a Real-time Assessment at least once every 30 minutes. Approved EOP-008-1 specifically requires entities to have capabilities 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. The SDT developed proposed TOP-001-3, Requirement R13 to be consistent with the intent of existing requirements. Proposed TOP-001-3, Requirement R13 has been previously modified to reflect industry comment in order to recognize that other entities may perform Real-time Assessment during EOP-008 scenarios. No change made.		
Oncor Electric Delivery LLC	No	Proposed Standard TOP-001-3 R9 States: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected entities of sustained outages of 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 sustained outages of telemetering

Organization	Yes or No	Question 1 Comment
		and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Proposed Standard TOP-001-3 R10 States:R10. Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator:10.2.1. Facilities,10.2.2. Status of Special Protection Systems, and10.2.3. Non-BES facilities. 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 R1O.2, R10.2.1., R10.2.2 and R10.2.3 be removed from the standard due to lack of regional flexibility. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to "a continuous duration exceeding its associated IROL Tv". This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncor's recommendation is to keep the existing 30 minute time limit.

Organization	Yes or No	Question 1 Comment
Response: The SDT removed the term 'negatively impacted' due to comments in a previous posting. The logic was that an entity would not be positively impacted by an outage so the term was redundant. No change made. The SDT believes that sufficient flexibility is provided in the revised language for Requirement R10. How an entity accomplishes the task is not in scope for standards. If there are lower cost alternatives available that meet the goal of the requirement, they may be used. In the situation cited, data exchanges will already be in place, or will need to be installed, to comply with other requirements such as proposed TOP-003-3, Requirement R5. Therefore, given the revised language, the SDT does not see any undue burden, financial or otherwise, to comply with this requirement. No change made. IROLs are, and always have been, determined by the Reliability Coordinator as per the approved FAC-011 and FAC-014 standards and passed along to Transmission Operators. T_v is part of this methodology. Whether multiple Transmission Operators are involved or not has no relevance as they must all adhere to what is provided by the Reliability Coordinator. No change made.		
Georgia Transmission Corporation	No	(1) GTC requests the drafting team remove the DP and LSE designation from Requirements R3 and R5 and develop separate requirements for the DP and LSE to comply with Operating Instructions to shed or shift load. By making this change, the requirements could be made clearer that the Operating Instructions that the DP and LSE receive from the TOP with respect to the defined term Operating Instruction, correspond to "impacting" the output of an Element of the BES (shed or shift load). Because the term Operating Instruction is tied to the BES, a standalone requirement is necessary to eliminate the ambiguity associated with entities with multiple registrations such as TOs who are also DP/LSE's that own BES equipment. It should be noted that this Standard does not apply to a Transmission Owner, but the field personnel who perform switching in substations of entities with both registration types are typically the same personnel. The level of Operating Instructions performed for multiple registration type (TO/DP/LSE) entities would be much more voluminous and burdensome due to the ownership of transmission equipment than the typical DP/LSE type entities for the same requirement. GTC believes the typical scenario the drafting team is considering is from a TOP control center to a DP/LSE dispatch center that

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		does not own BES equipment, but can impact the output of an Element of the BES (by shedding or shifting load). GTC urges the drafting team to consider this additional exposure of field personnel of TO/DP entities that switch in transmission substations to which the standard does not apply. Per discussions with Standard Drafting Team members and industry personnel, the scenario for DP/LSE's to receive Operating Instructions are limited to load shed or shift scenarios to preserve the reliability of the BES by the defined term associated with "impacting" the output of an Element of the BES. Exposing these multiple registration type entities to a set of mandatory standard requirements to which they do not apply such as those TOs and DPs identified above, demonstrates the potential flaw with the current language. With the following changes made to the requirements, GTC would be comfortable voting affirmative on this standard: o Each Distribution Provider and Load Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator to shed or shift load, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. o Each Distribution Provider and Load Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority to shed load or shift load, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. (2) Please note that M1 should be changed from "ensure" to "address" to match R1. (3) Part 10.1.3 and 10.2.3's reference to "Non-BES facilities" is outside the scope of reliability standards. Reliability standards are applicable to the BES, which would be Facilities. Refer to NERC's memo dated April 10, 2012 with respect to use of the term BES in Reliability Standards. The revised BES definition addresses Elements and Facilities that should be subject to the reliability standards through the BES exception process. Although the TOP will monitor Non-BES facilities in practice, there is no reason to include non-

Organization	Yes or No	Question 1 Comment
		BES Elements in the requirement subject to mandatory enforcement. Parts 10.1.3 and 10.2.3 that reference “non-BES facilities” should be struck.
Response: 1) Functional Model v5 determines what entities a Transmission Operator or Balancing Authority can issue Operating Instructions to and what those Operating Instructions can contain. Furthermore, the SDT believes that it would be counter-productive to set up individual requirements for entities that address specific types of operating Instructions. The resultant standard would be voluminous and impossible to understand. No change made. 2) The SDT has corrected the Measure. 3) The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term ‘Facilities’. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.		
Liberty Electric Power	No	The standard does not contain a requirement for the TO to identify the Operating Instruction as a reliablity instruction as opposed to a market instruction.
Response: Operating Instruction is a defined term and is used in this standard in that context. No change made.		
Manitoba Hydro	No	Manitoba Hydro agrees with changing the term “ensure” to “address” throughout the standard, however in M1 the term “ensure” remains even though its associated requirement R1 has “address”. We believe the intent was to replace “ensure” with “address” as it is in M2. In Pages 15 and 16 of TOP-001-3, Table of Compliance Elements, “Operations Planning” in the Time Horizon column of R1 through R6 should be deleted because they were deleted in Requirements R1 through R6.

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Response: The SDT has corrected Measure M1. This change was already made in the previously posted version. No change made.		
Lincoln Electric System	No	For smaller entities that do not own or operate a state estimator, the Real-time Assessment required in R13 would be overly burdensome, if not impossible, to meet internally. Although the drafting team indicates a third-party service may be utilized in lieu of an internal system, smaller entities would be wholly reliant on a third-party in order to maintain compliance with R13. This is of particular concern when considering that if a Protection System status were to change unexpectedly on a smaller entity's system, that entity would be expected to notify a third-party and then have that third-party perform a modified contingency analysis, pending availability, all within 30 minutes. Rather than treat all TOPs the same without consideration for size or risk to the BES, recommend that, at a minimum, the timeframe for conducting the Real-time Assessments be expanded or else allow the individual TOPs to establish the timeframe.
Response: The suggested language change to Requirement R13 presents ambiguity and is not measurable. There are many different ways for an entity to perform a Real-time Assessment. A small entity may be able to come up with any number of suitable methods that would not involve using Real-time Contingency Analysis. For example, the Reliability Coordinator or adjacent Transmission Operators could provide this service and data links should already be in place with these entities to comply with other requirements. No change made.		
CenterPoint Energy Houston Electric LLC	No	R1. - CenterPoint Energy agrees with the addition of “...direct actions or by issuing Operating Instructions” as well as using ‘address’ rather than ‘ensure’, however CenterPoint Energy prefers the manner in which the previous R1 was drafted. CenterPoint Energy suggests the following language: “Each Transmission Operator shall take direct actions or issue Operating Instructions to address the reliability of its Transmission Operator Area.”

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		R10.2 - 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 Reliability Coordinator'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. As long as R10.2 remains CenterPoint Energy cannot support the proposed Standard and therefore strongly recommends the SDT delete R10.2. R13. - CenterPoint Energy agrees that a Real-Time Assessment (RTA) should be run every 30 minutes, however the Company is concerned that events could occur that are outside of the Transmission Operator's control (Ex. Loss of ICCP data) that may prevent the Transmission Operator from performing a RTA as required; therefore there should be a caveat as to when exceeding the 30 minutes is allowed. CenterPoint Energy recommends the following language: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. In instances where a Real-Time Assessment cannot be performed (i.e. loss of ICCP data) the TOP shall take immediate action to restore Real-Time Assessment functionality. R14. - CenterPoint Energy suggests changing Operating Plan to Operating Plan(s).
Response: Requirement R1 has been changed due to comments received to provide additional clarity. See summary for language.		

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The SDT has changed the language of the requirement due to comments received. See summary for language. The SDT has clarified what it intended by monitoring in the revised language. The SDT believes that the suggested language is unnecessary. Obviously, a Transmission Operator is going to work as quickly as possible to restore functionality as it is in its best interests to do so. Loss of ICCP data is a major concern. Other standards point to redundancy for these situations that could alleviate the concern. Approved EOP-008-1, Requirement R1, Part 1.6.2 deals with what needs to happen due to loss of functionality. That requirement states that an entity is still responsible for managing the risk during such a situation. The SDT believes that ensuring that a Real-time Assessment is performed at least once every 30 minutes is not unrealistic or overly burdensome in today's operating environment. This is also consistent with approved IRO-008-1, Requirement R2. No change made. The SDT believes that the inclusion of guidance on what an Operating Plan should be in this situation as shown in Section F addresses the concern. No change made.		
HHWP	No	R16 states: "Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and analysis capabilities." Organizations should be free to designate its preferred method for approving planned outages of data equipment. This requirement imposes on all TOPs single process for data system outage approval. The requirement should be results based on not proscriptive of the method to achieve those results. This is a huge step backwards in the development of rational reliability requirements.
Response: The SDT believes that the requirement is written with sufficient flexibility to allow an entity to determine how to implement it and does not see how the requirement is overly prescriptive. The measure for this requirement does not specify a particular process or solution. No change made.		
American Transmission Company, LLC	Yes	ATC agrees with the changes to the proposed TOP-001-3, however, ATC recommends that Requirement R9 be modified by replacing "sustained" with "planned or sustained." This modification will provide clarity to the

Organization	Yes or No	Question 1 Comment
		requirement and align with comments made by the SDT during the October 16th TOP/IRO webinar that planned outages were in view.
Response: The SDT agrees that a change is required and has modified the language accordingly. See summary for language.		
Tri-State Generation and Transmission Association, Inc.	Yes	There was the addition of "sustained" for clarification in requirement R9. Tri-State wonders if the SDT meant to use the defined term "Sustained Outage" in this requirement or if they did not intend to use that defined term?
Response: The SDT did not intend to use the defined term, thus the lack of capitalization. The defined term applies only to Transmission outages which is not the condition here. The SDT has added a time element to the requirement language based on received comments. See summary for language.		
Central Lincoln People's Utility District		Central Lincoln recently participated in a load shedding drill led by our Host BA/TOP. The single most glaring problem we saw was one of validation. In the past we had always thought we would validate an R3 Directive or Operating Instruction by calling the TOP back at a known phone number. Our TOP informed us that such a validation method would not be possible during a real event, since all phones and switchboards would likely be busy. While objecting to our validation method, the TOP has failed to offer a suitable one. This leaves Central Lincoln with the choice of responding to an Operating Instruction to shed load coming from a scammer who has easy access TOP-001 on line, or risking a possible violation. Suggest the SDT begin looking at the question of validation, since without a validation method R3 poses a greater risk to reliability than it addresses.
Response: Communications is a concern for COM standards. For operating standards, such as the TOP standards, communication is considered to already be in place. The SDT suggests working with your Transmission Operator and Reliability Coordinator to work toward an acceptable resolution. Multiple technology options exist to address your concern. No change made.		

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DTE Electric Co.	Yes	We support the changes and have no concerns/comments to add.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
American Electric Power	Yes	
South Carolina Electric & Gas	Yes	

END OF REPORT