NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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 standards. These standards were posted for a 45-day public comment period from May 19, 2014 through July 2, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 71 sets of comments, including comments from approximately 186 different people from approximately 136 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 project page.

The SDT made changes to the following items in response to industry comments:

- **Definitions of Real-time Assessment and Operational Planning Analysis**:
    - Minor clarifying changes (see list of changes below for TOP-001-3 for details)
- **Proposed IRO-001-4**:
    - Requirements R2 and R3: deleted 'Transmission Service Provider' as it does not truly apply to these requirements
    - Measures and VSL language: revised as needed for consistency with requirement language changes
- **Proposed IRO-002-4**:
    - Requirement R1: deleted as it is redundant with proposed COM-001-2
    - Requirement R2: changed list of entities with whom the Reliability Coordinator is required to have data exchange capabilities, to show just Transmission Operator and Balancing Authority and other entities deemed necessary to allow for situations where a Reliability Coordinator exchanges data only with Transmission Operators and Balancing Authorities who in turn solicit information and data from other entities and relay it to the reliability Coordinator as well as situations where the Reliability Coordinator exchanges data directly to other entities
    - Requirement R3: added 'telecommunications' to provide System Operators the ability to control scheduling of planned telecommunication outages
    - Requirement R4: re-arranged the language to clarify the intent of what is to be monitored; clarified that sub-100 kV facilities are as identified as necessary by the Reliability Coordinator
    - Requirement R5: deleted 'and highly reliable' as unmeasurable
    - Requirement R2 VSL: changed from a binary (severe) to an incremental approach consistent with approved IRO-002-2, Requirement R1

  - Measures and VSL language: revised as needed for consistency with requirement language changes
- **Proposed IRO-008-2**:
  - Requirement R1: Minor revisions to clarify the SDT's intent, including changing 'Reliability Coordinator Wide Area' to 'Wide Area'
  - Requirement R2: deleted as duplicative of Requirement R3 as the plans can't be coordinated unless they have been reviewed
  - Requirement R3: minor revisions for consistency
  - Requirement R4: deleted 'NERC registered' as a modifier of 'entities' as unnecessary
  - Requirement R5: changed language to 'ensure' that the Real-time Assessment is performed to acknowledge the situation where capabilities are unavailable and back-up methods are employed, or where an agreement for a third party to perform the Real-time Assessment exists
  - Requirement R7: deleted as duplicative with proposed IRO-001-4 Requirement r1
  - Data retention: changed from three months to 90 days for consistency; Requirement R5 and Measure M5 – changed to a rolling 30 day period consistent with approved IRO-008-1
  - Requirement R1 VSL: made minor grammatical corrections for consistency
  - Requirement R5 VSL: made consistent with approved IRO-008-1 Requirement R2
- **Proposed IRO-010-2**:
  - Effective date: changed first step from 10 months to 9 months to better align with possible approval dates
  - Requirements R1 and R2 VRF: changed from 'Medium' to 'Low' for consistency with approved IRO-010-1a Requirements R1 and R2
  - Requirement R2 VSL: added explanatory text as to the SDT intent on how to apply the VSLs
  - Requirement R3: deleted Planning Coordinator and Transmission Planner as those entities would not be involved in submitting data as envisioned in the data specification concept
  - Measures and VSL language: revised as needed for consistency with requirement language changes
- **Proposed IRO-014-3**:
  - Requirement R1: added 'implemented' so that an entity must both 'have' and 'implement' the plan
  - Requirement R1, Part 1.1: Revised to better align with the other parts of the Requirement
  - Requirement R1, Part 1.5: deleted as duplicative with proposed IRO-001-4 Requirement R1
  - Requirement R1, Part 1.6: Revised to better align with the other Parts of the requirement and changed 'weekly conference calls' to 'periodic communications to

support reliable operations' so that communications will occur as needed and to allow for other forms of communication
    - Requirement R3: deleted as duplicative of proposed IRO-014-3 Requirement R1 Part 1.1
    - Requirement R4: deleted as duplicative with proposed IRO-014-3 Requirement R1, Part 1.5
    - Requirement R5 (now R3): added 'expected or actual' to Emergency to clarify the intent of the requirement and also added 'in its Reliability Coordinator Area' to bound the requirement
    - Requirement R6 (now R4): replaced 'problem' with 'Emergency' for consistency
    - Requirement R7 (now R5): added 'in its Reliability Coordinator Area' to bound the requirement and also added 'impacted' to clarify the obligation
    - Requirement R9 (now R7): changed 'entity' to 'Reliability Coordinator' for clarity
    - Requirement R2 VSL: shifted the Low and Moderate VSLs for consistency with approved practices
    - Measures and VSL language: changed language as needed for consistency with requirement language changes
- **Proposed IRO-017-1**:
    - Purpose: added the time frames in which coordination of outages is intended to take place
    - Requirement R1, Part 1.1.2: deleted 'prior to submitting to Reliability Coordinators' as each Reliability Coordinator is able to define the process to best fit its area
    - Requirement R1, Part 1.1.3: changed 'Reliability Coordinator Wide Area' to 'Wide Area' for consistency
    - Requirement R1, Part 1.1.5: deleted as redundant and unnecessary
    - Requirement R1 VRF: changed from 'Low' to 'Medium' to be consistent with proposed IRO-005-3.1a Requirement R6
    - Requirement R2: changed 'follow' to 'perform the function specified in' for clarity
    - Requirement R2 VRF: changed from 'Low' to 'Medium' to be consistent with proposed IRO-017-1 Requirement R1
    - Requirement R4: re-worded to emphasize the joint development aspects of the requirement and to provide a bound on the timeframe
    - Requirement R1 VSL: changed to incremental approach for consistency with proposed IRO-005-3.1a Requirement R6
    - Measures and VSL language: changed language as needed for consistency with requirement language changes
- **Proposed TOP-001-3**:
    - Definitions: added 'applicable' to modify 'inputs' to indicate that an entity can only use as inputs that data which it actually has and changed 'contracted' to 'third-party'- for clarity

- Requirement R1: deleted first instance of 'Transmission Operator Area' to address comments on entities and deleted 'functions' for clarity as the issue is reliability and not undefined functions
- Requirement R2: changed for consistency with requirement R1 language
- Requirement R4: deleted 'citing one of the specific reasons shown in Requirement R3' as it is redundant
- Measure M4: corrected entity name to 'Generator Operator'
- Measure M5: corrected entity from 'Transmission Operator' to 'Balancing Authority'
- Measure M6: corrected entity from 'Balancing Authority' to 'Transmission Operator'
- Requirement R7: deleted 'Balancing Authority' as it can't respond to other Transmission operators – if it can assist it should receive instructions from its Transmission Operator; added 'other' to provide clarity as to who is being assisted; added 'and able as assistance can only be provided if the entity is able to provide it
- Requirement R8: added 'known' and 'known other' to modify 'impacted' to provide boundaries to focus the notification
- Requirement R9: deleted 'negatively' to clarify that any impacted entity should receive notification; deleted 'telecommunication' as it is duplicative of proposed COM-001—2 Requirement R10
- Measure M9: corrected the language to correspond with the language of requirement R9
- Requirement R10: re-arranged the language to provide clarity as to the intent of what is to be monitored; clarified that sub-100 kV facilities are as identified to avoid redundancy and provide clarification
- Requirement R13: Revised 'perform' to 'ensure' that the Real-time Assessment 'is performed' to acknowledge the situation where capabilities are unavailable and back-up methods are employed, and to allow for situations where arrangements exist for a third party to perform the real-time Assessment
- Requirement R16: added 'maintenance' and 'telecommunication' for consistency with proposed IRO-002-4 Requirement R3
- Requirement R17: made corresponding changes to match up with Requirement R16
- Requirement R18: deleted 'Generator Operator' as the Generator Operator will receive instructions as to the parameter to use; changed 'derived limits' to 'SOLs' to clarify the actual limits being discussed in the requirement
- Requirements R19 and R20: added for consistency with proposed IRO-002-4, Requirement R1
- Data retention: changed data retention for operator logs to 90 calendar days for consistency with voice recordings
- Requirement R8 VSL: added a gradated approach to account for differential impacts of the VSLs on smaller entities
- Measures and VSLs: Revised as needed for consistency with changes to requirements

- **Proposed TOP-002-4**:
  - Definition: added 'applicable' to modify 'inputs' to indicate that an entity can only use as inputs that data which it actually has and changed 'contracted' to third-party- for clarity
  - Requirements R3 and R5: deleted 'NERC registered' from entities so that entities identified in the plan are notified regardless of NERC registration
  - Data retention: changed data retention for operator logs to 90 calendar days for consistency with voice recordings
  - Measures and VSLs: Revised as needed for consistency with changes to requirements
- **Proposed TOP-003-3**:
  - Effective date: changed first step from 10 months to 9 months to better align with possible approval dates
  - Requirement R5: deleted 'Interchange Authority' as no data comes directly from that entity
  - Requirement R5 VSL: added increments for consistency with approved IRO-010-1a Requirement R1
  - Measures and VSLs: Revised as needed for consistency with changes to requirements
- **Implementation Plan for proposed IRO-010-2 and TOP-003-3**
  - Changed first step from 10 months to 9 months to better align with possible approval dates
  - Added language to account for different possibilities in the timing of regulatory approvals of this project and the petition that includes proposed COM-001-2 and the definition of Operating Instruction

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	Sandra Shaffer	PacifiCorp						X				
N/A													
2.	Group	Guy Zito	Norteast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co, of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5

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

8.	Matt Goldberg	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company		1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
22.	Brian Shanahan	National Grid	NPCC	1
23.	Wayne Sipperly	New York Power Authority	NPCC	5
24.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1

				1	2	3	4	5	6	7	8	9	10
3.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

N/A

				1	2	3	4	5	6	7	8	9	10
4.	Group	Phil Hart	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

Additional Member		Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
5.	Group	John A. Libertz	FRCC Operating Committee (Member Services)	X				X					

N/A

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	1, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
N/A													
8.	Group	Stuart Goza	SERC OC Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gerald Beckerle	Ameren	SERC	1, 3
2.	William Berry	OMU	SERC	3
3.	Phil D'Antonio	PJM	SERC	2
4.	Dan Roethemeyer	Dynegy	SERC	5
5.	Joel Wise	TVA	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company;	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Southern Company Generation; Southern Company Generation and Energy Marketing										
N/A													
10.	Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton	NERC Compliance Policy	NPCC	5
2.	Randi Heise	NERC Compliance Policy	SERC	1, 3, 5, 6
3.	Connie Lowe	NERC Compliance Policy	RFC	5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Carol Chinn	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	1
8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	City of Green Cove Springs	FRCC	3
10.	Mike Blough	Kissimmee Utility Services	FRCC	5
11.	Tom Reedy	Florida Municipal Power Pool	FRCC	6

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			1
2.	Lee Schuster			3
3.	Dale Goodwine			5
4.	Greg Cecil			6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3

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

2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	S. Tom Abrams	Santee Cooper	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tom Abrams	Santee Cooper	SERC	1, 3, 5, 6
2. Rene Free	Santee Cooper	SERC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15. Group	Erika Doot	Bureau of Reclamation	X				X					

Additional Member	Additional Organization	Region	Segment Selection
1. Rick Jackson	Bureau of Reclamation	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Patricia Robertson	BC Hydro and Power Authority	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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. 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. David Thompson		SERC	5
4. Marjorie Parsons		SERC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	Cindy Stewart	FirstEnergy	X		X	X	X	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.	William J Smith	FirstEnergy Corp	RFC	1
2.	Douglas G Hohlbaugh	Ohio Edison	RFC	4
3.	Kenneth J Dresner	FirstEnergy Solutions	RFC	5
4.	Kevin J Querry	FirstEnergy Solutions	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19. Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Bensky	ITC Holdings	SPP	1
2.	Richard Bohnet	Omaha Public Power District	MRO	1, 3, 5
3.	Jamison Cawley	Nebraska Public Power District	MRO	1, 3, 5
4.	Michelle Corley	Cleco Power	SPP	1, 3, 5, 6
5.	Dave Dieterich	Omaha Public Power District	MRO	1, 3, 5
6.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
7.	Abubaker Elteriefi	ITC Holdings	SPP	1
8.	Neal Faltys	Omaha Public Power District	MRO	1, 3, 5
9.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
10.	Vinit Gupta	ITC Holdings	SPP	1
11.	Robert Hirchak	Cleco Power	SPP	1, 3, 5, 6
12.	Brett Holland	Kansas City Power & Light	SPP	1, 3, 5, 6
13.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
14.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
15.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
16.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
17.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
18.	Ron Losh	Southwest Power Pool	SPP	2
19.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
20.	Shannon Mickens	Southwest Power Pool	SPP	2
21.	Michael Moltane	ITC Holdings	SPP	1
22.	Jim Nail	City of Independence, MO	SPP	3
23.	Si Nguyen	Omaha Public Power District	MRO	1, 3, 5
24.	Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
25.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5

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

26.	Johnna Sargent	Omaha Public Power District	MRO	1, 3, 5
27.	Don Schmit	Nebraska Public Power District	MRO	1, 3, 5
28.	John Shipman	Omaha Public Power District	MRO	1, 3, 5
29.	Sing Tay	Oklahoma Gas and Electric	SPP	1, 3, 5
30.	Josh Verzal	Omaha Public Power District	MRO	1, 3, 5

20.	Group	Ben Engelby	ACES Standards Collaborators	1	2	3	4	5	6	7	8	9	10
									X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ginger Mercier	Prairie Power, Inc.	SERC	3
2.	Mohan Sachdeva	Buckeye Power, Inc.	RFC	3, 4
3.	Lucia Beal	Southern Maryland Electric Cooperative	RFC	3
4.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
5.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
6.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
7.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
8.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
9.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
10.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mathew Goldberg	ISO-NE	NPCC	2
2.	Ben Li	IESO	NPCC	2
3.	Cheryl Moseley	ERCOT	ERCOT	2
4.	Charles Yeung	SPP	SPP	2
5.	Terry Bilke	MISO	MRO	2
6.	Ali Miremadi	CAISO	WECC	2

22.	Group	Jared Shakespeare	Peak Reliability	1	2	3	4	5	6	7	8	9	10
				X									

N/A

23.	Group	Andrea Jessup	Bonneville Power Administration	1	2	3	4	5	6	7	8	9	10
				X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

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

1. John Anasis	Technical Operations	WECC	1
2. Steve Hitchens	Technical Operations	WECC	1
3. Tanner Brier	Generation Scheduling	WECC	5
4. Stacen Tyskiewicz	Energy Management Systems		1
5. Steve Kerns	Short Term Planning		6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
24. Individual	Scott McGough	Georgia System Operations			X	X						
25. Individual	Greg Froehling	Rayburn Country Electric Cooperative			X							
26. Individual	John Brockhan	CenterPoint Energy Houston Electric LLC.	X		X							
27. Individual	Tom Haire	Rutherford EMC			X							
28. Individual	Heather Bowden	EDP Renewables North America LLC					X					
29. Individual	Terry Volkmann	Volkmann Consulting								X		
30. Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
31. Individual	Chris scanlon	Exelon Ccompanies	X		X		X	X				
32. Individual	Ronnie Hoeinghaus	City of Garland	X		X		X					
33. Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
34. Individual	Glenn Pressler	CPS Energy	X		X		X					
35. Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
36. Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
37. Individual	Anthony Jablonski	ReliabilityFirst										X
38. Individual	Andrew Z. Pusztai	American Transmission Company	X									
39. Individual	Thomas Foltz	American Electric Power	X		X		X	X				
40. Individual	David Austin	NIPSCO	X		X		X	X				
41. Individual	Dave Willis	Idaho Power	X									
42. Individual	Laurie Williams	PNMR	X		X							
43. Individual	David Kiguel	n/a								X		
44. Individual	Venona Greaff	Occidental Chemical Corporation							X			
45. Individual	Catherine Wesley	PJM Interconnection		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
46.	Individual	Thomas Standifur	Austin Energy	X		X		X		X			
47.	Individual	David Jendras	Ameren	X		X		X	X				
48.	Individual	Charles Rogers	Consumers Energy			X	X	X					
49.	Individual	Daniel Duff	Liberty Electric Power, LLC					X					
50.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
51.	Individual	Scott Langston	City of Tallahassee	X									
52.	Individual	Bill Fowler	City of Tallahassee			X							
53.	Individual	Josh Smith	Oncor Electric Delivery LLC	X									
54.	Individual	Michael Moltane	ITC	X									
55.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
56.	Individual	Ayesha Sabouba	Hydro One	X		X							
57.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
58.	Individual	Leonard Kula	Independent Electricity System Operator		X								
59.	Individual	Ayesha Sabouba	Hydro One	X		X							
60.	Individual	James Nail	INDN - Independence Power & Light					X					
61.	Individual	NIck Braden	Modesto Irrigation District			X	X	X					
62.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
63.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
64.	Individual	Joe Tarantino	Sacramento Municipal Utility District/Balancing Authority Northern California	X		X	X		X				
65.	Individual	Gordon Dobson-Mack	Powerex Corp.						X				
66.	Individual	Richard Vine	California ISO		X								
67.	Individual	Karin Schweitzer	Texas Reliability Entity										X
68.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
69.	Individual	Joshua Andersen	Salt River Project	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
70.	Individual	Rich Salgo	NV Energy	X		X		X					
71.	Individual	Terry Harbour	MidAmerican Energy	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 has considered your support of the indicated comments in its deliberations.

Organization	Agree	Supporting Comments of "Entity Name"
Santee Cooper	Agree	We agree with the comments submitted by SERC OC Group.
Tennessee Valley Authority	Agree	SERC OC Review Group
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP
Kansas City Power and Light	Agree	SPP - Robert Rhodes
City of Tallahassee	Agree	The FRCC Operating Committee (Member Services)
Omaha Public Power District	Agree	SPP RTO Comments submitted by Robert Rhodes.
Powerex Corp.	Agree	BC Hydro's comments submitted by Patricia Robertson.
ITC		SPP Standards Group
Lincoln Electric System		MRO NSRF
Response: Thank you for your response.		

1. Do you agree with the changes made to proposed IRO-001-4? 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:

R2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	To be consistent with the format of other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention (page 7). An Operating Instruction applies to both Normal and Emergency operations. Therefore, the VSL should be graduated similar to COM-002-4 R5. OI issued during an Emergency is a Severe VSL and OI issued during Normal events is a Moderate VSL.
Response: Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure. For VSL comment, see response to question 14.		
FRCC Operating Committee (Member Services)	No	R1 - Requirement R1 is not needed. This responsibility is inherent to the Functional Model and does not need to be a requirement. At a minimum, we recommend removal of the Operations Planning horizon to narrow the focus of intent. As defined, the term Operating Instruction applies only to

Organization	Yes or No	Question 1 Comment
Seminole Electric Cooperative, Inc. Florida Municipal Power Agency		“Real-time operation of the interconnected BES.” In addition, the term Operating Instruction is too broad in scope because it applies to any “change in state, status, output, or input of an Element of the BES.” The amount of documentation required for evidence would be very burdensome. R2 - TSPs are not listed in the Functional Model for corrective actions issued by the RC. TSPs do not take actions to alter the state of the BES. We recommend to remove TSPs from this requirement. See comments supplied to R1 above. R3 - TSPs are not listed in the Functional Model for corrective actions issued by the RC. TSPs do not take actions to alter the state of the BES. We recommend to remove TSPs from this requirement. See comments supplied to R1 above. In addition, a correction is needed to refer to R1, instead of R2, when referencing the Operating Instruction issued by its RC.
Response: R1. The SDT believes Requirement R1 is needed and is responsive to concerns raised by FERC in the NOPR. The Operations Planning Time Horizon is required to include Operating Instructions issued by a Reliability Coordinator based on conditions seen in studies, from day-ahead up to and including seasonal, that may impact the Real-time reliability of the Reliability Coordinator Area. The use of Operation Instruction is consistent with proposed COM-002-4. Proposed COM-002-4 (pending regulatory approval) was approved by the Board and the SDT uses Board approved standards and definitions. No change made. R2. The SDT agrees and has deleted Transmission Service Provider from the requirement. See summary consideration for revision. R3. The SDT agrees and has deleted Transmission Service Provider from the requirement. With the corresponding deletion of Transmission Service Provider in Requirement R2, the Transmission Service Provider no longer appears as an applicable entity in any of the requirements and has also been deleted from the Applicability Section. See summary consideration for revision. The SDT corrected the error in Requirement R3 to refer to Requirement R1 instead of Requirement R2.		

Organization	Yes or No	Question 1 Comment
MRO NERC Standards Review Forum	No	R3 is predicated on R2 and only allows entities the inability to perform the issued Operating Instruction based on “unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements”. The entity then must cite which specific reason why they cannot perform the Operating Instruction. The NSRF does not agree with this due to the limited possibilities for not performing the Operating Instruction. The NSRF recommends deleting “citing one of the specific reasons shown in Requirement R3”, as this wording does not prevent instability, uncontrolled separations or Cascading outages. We do not need rules this specific, the issuing entity can always ask why the receiving entity cannot perform the Operating Instruction.
Response: The SDT agrees that there are limited possibilities for not performing a Reliability Coordinator’s Operating Instruction and therefore believes it is important to provide the specific criteria for not doing so. However, the SDT agrees it is not necessary or beneficial to reliability to cite the reasons at the time of the event. The specific reason(s) why an entity was unable to perform an Operating Instruction would be discussed after the issue requiring action was resolved. The reason(s) would still need to be in accordance with those specified in Requirement R2.		
Duke Energy	No	Duke Energy is concerned that R1 and R2 as written do not appear to be Results-Based as laid out in the Rules of Procedure. The requirement that the RC “act” to ensure the reliability of its RC area is not only a requirement that the RC do its job for which other requirements are applicable, but also a requirement that could be interpreted to require the RC “act” to cover the full scope of any related RC reliability tasks listed under the NERC Functional Model. We believe such language should be removed and that the requirement should focus strictly on the communication desired when needed to ensure the reliability of the RC area. The definition of Operating Instruction makes these requirements (and standard as a whole), too broad in nature. The definition of Operating

Organization	Yes or No	Question 1 Comment
		Instruction carries past the parameters of action in an Emergency situation, and includes all actions. To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written. R1: Duke Energy suggests re-writing R1 as follows: ”Each Reliability Coordinator shall issue Reliability Directives, as necessary, to ensure the reliability of its Reliability Coordinator Area.” As written, the language requires the RC to act to ensure the reliability if its area, which is similar to writing a requirement that the RC comply with all other RC requirements. The suggested language addresses that point and would eliminate the ambiguity that currently exists in the proposal that an RC must issue an Operating Instruction for all communications, and not when actually warranted. As written, this requirement could be interpreted to suggest that an RC would be non-compliant if at any time they did not issue an Operating Instruction notwithstanding system conditions. In any communication, the RC has the authority to issue a Reliability Directive whenever the circumstances warrant such authority. Also, we would like to add that the RC’s responsibilities outlined in R1 are inherent to the NERC Functional Model. Ultimately, we question the necessity of the proposed R1. R2: Duke Energy questions the addition of the TSP into the proposed R2. This requirement references compliance by an applicable entity to an RC’s Operating Instruction. An Operating Instruction is considered to be an action that takes place during Real-time operations. Per the NERC Functional Model, the relationship between the RC and the TSP is considered “Ahead of Time” in nature. Additionally, the Functional Model does not provide that an RC may actually direct a TSP to act, only that an RC may coordinate with a TSP on transmission system limitations. As with our

Organization	Yes or No	Question 1 Comment
		prior comment, we believe this requirement should be applicable those receiving Reliability Directives. R3: See our comment above regarding the relationship between the RC and the TSP above. Also, there appears to be an improper reference to R2 in this requirement. We believe the SDT meant to reference R1 instead, due to the actual issuance of an Operating Instruction from the RC takes place in R1, and not R2.
Response: R1 - The SDT believes Requirement R1 is needed and is responsive to concerns raised by FERC in the NOPR. The SDT's decision to utilize the term Operating Instruction was in part due to the concept that a directive is inclusive within its definition. The SDT believes the use of Operating Instruction(s) allows Reliability Coordinators and Transmission Operators to address or prevent situations that could lead to an Emergency. The Reliability Directive definition was never approved by FERC (see NOPR) and will eventually be withdrawn. The use of Operation Instruction is consistent with proposed COM-002-4. Proposed COM-002-4 (pending regulatory approval) was approved by the Board. No change made. For VSL comment, see response to question 14. R2 – The SDT agrees and has deleted Transmission Service Provider from the requirement. However, the Operations Planning Time Horizon is required to include Operating Instructions issued by a Reliability Coordinator based on conditions seen in studies, from day-ahead up to and including seasonal, that may impact the Real-time reliability of the Reliability Coordinator Area. See summary consideration for revision. R3 – The SDT agrees and has deleted Transmission Service Provider from the requirement. See summary consideration for revisions. The SDT corrected the error in Requirement R3 to refer to Requirement R1 instead of Requirement R2. See summary consideration for revisions.		
Bureau of Reclamation	No	The Bureau of Reclamation (Reclamation) disagrees with the use of the term Operating Instruction in IRO-001-4 R1. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Often Reliability Coordinators and Transmission Operators may not be aware of generation equipment constraints or other obligations (e.g.

Organization	Yes or No	Question 1 Comment
		water delivery schedules for hydroelectric projects). Reclamation believes that IRO-001-4 should establish Reliability Coordinator authority to issue Reliability Directives to address an Emergency or avoid an Adverse Reliability Impact.
BC Hydro and Power Authority	No	The new Requirement has the Reliability Coordinator issuing "Operating Instructions" rather than "Reliability Directives". The scope of "Operating Instructions" broadens to non-emergency situations. BC Hydro does not support this increase in scope.
Consumers Energy	No	I am opposed to replacement of Reliability Directive with Operating Instruction. Reliability Directive is a much stronger term than Operating Instruction, and should be used in this context.
Response: The SDT's decision to utilize the term Operating Instruction was in part due to the concept that a directive is inclusive within its definition. The SDT believes the use of Operating Instruction(s) allows Reliability Coordinators and Transmission Operators to address or prevent situations that could lead to an Emergency. The Reliability Directive definition was never approved by FERC (see NOPR) and will eventually be withdrawn. The use of Operation Instruction is consistent with proposed COM-002-4. Proposed COM-002-4 (pending regulatory approval) was approved by the Board. No change made.		
SPP Standards Review Group	No	Since there is no red-line for IRO-001-4, delete the last sentence in the Rationale Box for the Applicability Section.
Response: The SDT agrees and the last sentence in the rationale box in the Applicability section has been removed.		
ACES Standards Collaborators	No	(1) We agree with the removal of the PSE and LSE from IRO-001-4. It would be highly unusual for an RC to issue a directive to a PSE or LSE. (2) The use of "operating instruction" as a FERC-approved defined glossary term is problematic because FERC has not approved COM-002-4. We recommend including the proposed definition of Operating Instruction, as

Organization	Yes or No	Question 1 Comment
		stated in COM-002-4, in the Rationale Box above R1 that discusses the change from Reliability Directive to Operating Instruction. (3) We support the consolidation of IRO-004-2 by inserting the Transmission Service Provider into R2 and R3. We encourage the drafting team to further look for opportunities to reduce requirements and redundancy in the IRO and TOP standards. (4) For Requirement R2, we question the phrase "cannot be physically implemented" and how that term would differ from violations of safety or equipment requirements. We recommend the SDT provide examples to support the new proposed language. (5) For Requirement R3, we believe this requirement should be removed in its entirety. It meets Paragraph 81 criteria as an administrative documentation requirement. R2 clearly states that the applicable functions must comply unless there is a violation of other factors. The burden in R2 is on the entity to comply or to prove why they cannot comply. Therefore R3 is not needed. (6) We question the binary nature of the VSL tables and ask the SDT to consider graduated treatment of violations.
Response: (1) Thank you for your support. (2) The use of Operation Instruction is consistent with proposed COM-002-4. Proposed COM-002-4 (pending regulatory approval) was approved by the Board and the SDT uses Board approved standards and definitions. No change made. (3) Thank you for your support. (4) The phrase "cannot be physically implemented" is intended for scenarios where, for example, a line or transformer is requested to be returned to service to resolve an issue, but the conductor is not in the air or the transformer has had its oil drained for maintenance, for example. No change made.		

Organization	Yes or No	Question 1 Comment
(5) The SDT disagrees that Requirement R3 is not needed. Requirement R3 requires communication to the Reliability Coordinator when an Operating Instruction cannot be performed. However, the SDT agrees it is not necessary or beneficial to reliability to cite the reasons at the time of the event. The specific reason(s) why an entity was unable to perform an Operating Instruction would be discussed after the issue requiring action was resolved. The reason(s) would still need to be in accordance with those specified in requirement R2. (6) For VSL comment, see response to question 14.		
Rayburn Country Electric Cooperative	No	I believe clarity and efficiency could be achieved by combining IRO-001-4 and TOP-001-3.Both Standards are intended to insure reliability of the interconnection. The IRO standards family itself is “Interconnection Reliability Operations and Coordination” and the purpose statement for TOP-001-3 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.” The strategy could be accomplished by defining the responsibilities by two groups, those that have the authority to deliver an Operating Instruction and the second group as those who need to receive and act on an Operating Instruction. This would allow 6 requirements in my example to follow, to be condensed into 2 requirements. Delivering Entity Any one of the following functions: o Reliability Coordinator, o Balancing Authority, o Transmission Operator Receiving Entity Any one of the following functions: o Balancing Authority, o Transmission Operator, o Transmission Service Provider, o Generator Operator, o Load Serving Entity o Distribution Provider R2 Receiving Entity shall comply with the Delivering Entities Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. R3 Receiving Entity shall inform the Delivering Entity of its inability to perform the Operating Instruction issued by its Delivering Entity

Organization	Yes or No	Question 1 Comment
		in Requirement R2 citing one of the specific reasons shown in Requirement R2.
Response: The SDT appreciates your creative approach to consolidating and simplifying requirements but believes all of the requirements are necessary and must be separate to reflect the operational hierarchical structure. For instance, Requirement R3 does not apply to a Transmission Operator because a Transmission Operator cannot issue operating instructions to another Transmission Operator. Requirement R5 is similar in that a Balancing Authority cannot issue Operating Instructions to other Balancing Authorities. However, a Reliability Coordinator can issue Operating Instructions to both. Combining the requirements and respecting this operational hierarchy would make the requirements quite cumbersome. In addition, this project inherited the scope of Projects 2006-06 and 2007-03 which indicated industry preferences for keeping the functions separate. No change made.		
City of Garland	No	Requirement 1Concern # 1The volume of applicable Reliability Standards already requires action or directing others to act. In an audit situation, the NERC auditor cannot find a possible violation for failing to “act or direct others to act” without also identifying which Requirement in which NERC standard that required action - therefore, there is already an existing requirement to act or direct others to act without this proposed requirement. Recommendation # 1Replace this proposed requirement with the existing requirements concerning authority. Concern # 2The “act, or direct others to act” is executed by experienced, NERC Certified Personnel who make decisions in real-time based on the information available at that time. To continuously compile supporting information to support each decision / action taken by experienced, NERC Certified Personnel for an audit situation will be time consuming, labor intensive and will require voluminous data storage. Also, unless there is some event that triggers an event analysis, how is the auditor going to determine the “when”, “what” and “how” in a normal audit months or years later to decide whether the entity is in violation. Sometimes the correct action to take is “no action” based on the information available at

Organization	Yes or No	Question 1 Comment
		the time. Recommendation # 2Replace this proposed requirement with the existing requirements concerning authority.
Austin Energy	No	City of Austin dba Austin Energy (AE) does not agree with the change to R1, which removes the "clear decision-making authority" language from the previous standard. AE believes the authority language provides clarity and substance in an easily recognizable format. System Operators are familiar with the NERC Reliability Standards, but they are not as well versed in the specifics of FERC Orders, such as FERC Order 693a, paragraph 112. AE offers more comments on this matter with regards to TOP-001-3 below.
Response: The SDT intentionally removed the existing requirements concerning authority because it does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act. The IERP Report also points to actions versus authority which is performance-based. No change made.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP ("ICLP") believes the changes made to IRO-001-4 have reintroduced enormous administrative overhead into our compliance approach for Operating Instructions. That issue was resolved in COM-002-4 by focusing on the training of GOP front-line operators who receive Operating Instructions - not their actual execution. This was a necessary step because the range of communications that constitute an Operating Instruction is very broad, and it is unreasonable to expect that every one of them will be perfectly executed and documented to the liking of an audit team. The problem is that there are two distinct categories of interest. The first are those which are issued as an urgent action, and which are really the target of IRO-001-4. It is appropriate to expect that those Operating Instructions issued during Emergencies and near-Emergencies should be handled in a zero-tolerance manner. However, those issued in the normal course of business - by far the larger category - must be excluded. IRO-001-4 R1 has simply removed the limitation that the applicable Operating

Organization	Yes or No	Question 1 Comment
		Instructions are those made during an Emergency or Adverse Reliability Impact. This ambiguity can be resolved in different ways. The drafting team could add language back to Requirement R1 specifically limiting its applicability to a set of defined circumstances. A better method may be to require the RC to identify the Operating Instruction as "critical" to the recipient in order to heighten awareness and ensure compliance. Furthermore, ICLP does not agree with the removal of the qualifier in R3 that the Operating Instruction recipient must notify the issuer "upon recognition" of its ability to perform it. This language was added to account for situations where the inability to act is recognized sometime after the instruction is issued. This happens in real-time and it is not appropriate to penalize an entity who initially believes that they can execute a critical Operating Instruction in good faith - but finds out later they cannot. As such, the qualifier should be reinstated.
Response: The SDT believes the use of Operating Instruction is responsive to concerns raised by FERC in the NOPR. The SDT's decision to utilize the term Operating Instruction was in part due to the concept that a directive is inclusive within its definition. The SDT believes the use of Operating Instruction(s) allows Reliability Coordinators and Transmission Operators to address or prevent situations that could lead to an Emergency by issuing specific command(s) for action to be taken. As stated in the definition, discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command, which the SDT believes addresses the concern of administrative burden. The "upon recognition" wording was not removed as it is not in the currently enforceable version of this standard. The SDT feels Requirements R2 and R3 as currently worded correctly address a situation where an entity initially feels an Operating Instruction can be executed, but later realizes it cannot. Once the entity realizes the Operating Instruction cannot be executed, it must notify the Reliability Coordinator. No change made.		
Idaho Power	No	N/A
MidAmerican Energy	No	

Organization	Yes or No	Question 1 Comment
Response: Without specific comments, the SDT is unable to respond.		
Liberty Electric Power, LLC	No	There is no requirement for the RC to identify the Operating Instruction as such. In some areas the same individual could be issuing a Directive, an Operating Instruction, or a market-related instruction. Unless the requestor identifies the status of the request, the receiver will have no idea if he is required to comply.
Response: The SDT believes the definition of Operating Instruction adequately identifies the conditions for issuing the Operating Instruction. Proposed COM-002-4 lays out the requirements for three-part communication involving Operating Instructions. No change made.		
Electric Reliability Council of Texas, Inc.	No	The retirement of IRO-004-2 is predicated on the concept that an Operating Instruction applies outside of the real-time time horizon. Operating Instruction as defined is for real-time and not for the Operations Planning time horizon. As such, it does not cover the purpose and timeframe identified in IRO-004-2. Directing others to act outside of real time does not make sense as deciding to take actions in a future time is a plan, not a real-time instruction. Additionally Operating Instructions have no COM-002-4 requirements associated with a Transmission Service Provider. In summary, while the use of the term Operating Instruction provides some uniformity, it simply does not work in its current form for the Operations Planning timeframe. Some instructions outside of the real-time time horizon are carried out by systems or on non-recorded lines and perhaps even by operations support personnel. The definition when created by the OPCP SDT was for COM-002-4 and was not for the construct of current proposed IRO-001-4 draft. Any modifications to the definition could create issues for the COM-002-4 standard as well. ERCOT recommends removal of the operations planning time horizon and address needs separately for expectations related to that time horizon for issuing instructions as

Organization	Yes or No	Question 1 Comment
		necessary to plan for reliable operations. As an alternative, the definition could be modified and COM-002-4 modified to include "Real Time" in front of every instance of usage for "Operating Instruction" effectively moving real time out of the definition and making it an individual qualifier for each requirement as needed. For IRO-001 R1, ERCOT believes the existing requirement does not provide overlap as it ensures that entities have policies or controls providing such authority. The body of all other requirements provides the basis of the actual implementation of such authority through actions or directing to act. The current requirement appears now to be redundant with every other requirement that requires action from an RC. The evolution of this requirement has lost the "clear decision-making authority" portion which while not action-oriented provides a basis for System Operator judgment and authority. Having requirements worded this way can be a blanket requirement utilized by auditors to second guess an operator's perceived actions or inactions as a violation, while not regarding the clear decision-making authority a System Operator exercises with information available at a specific point in time. Additionally, when the current version IRO-001-1.1 loses the "within 30 minutes" language, it loses the original construct of this being a real time requirement and not something applied to same day or operations planning timeframe. It loses its purpose when trying to simply consolidate IRO-004 language with it. ERCOT recommends maintaining existing R1 language as much as possible as follows: "Each Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by other entities to preserve the reliability of its Reliability Coordinator Area. These actions shall be taken without delay, but no longer than 30 minutes. [Violation Risk Factor: High][Time Horizon: Real-time Operations]". This would preserve

Organization	Yes or No	Question 1 Comment
		the original purpose of the requirement, address NOPR paragraph 64, and provide a timeliness requirement where appropriate for all requirements that require action by an RC in real time without redundancy. Additionally, recommend changing R1 to be actionable to current proposed language is inconsistently applied (e.g. TOP-001-3 R16, R17).
Response: The SDT believes the Operations Planning Time Horizon is required to include Operating Instructions issued by a Reliability Coordinator based on conditions seen in studies, from day-ahead up to and including seasonal, that may impact the Real-time reliability of the Reliability Coordinator Area. The SDT sees the definition as being 'timeless'. It does not state that an Operating Instruction is only issued in Real-time. It says that they can only be issued by those responsible for Real-time operations which would be the Reliability Coordinator, Transmission Operator, and Balancing Authority by definition. No change made. However, the SDT has removed Transmission Service Provider from Requirements R2 and R3. See summary consideration for revision. The SDT intentionally removed the existing requirements concerning authority because it does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act. The IERP Report also points to actions versus authority which is performance-based. No change made. The SDT believes that the language is consistently applied. No change made.		
Texas Reliability Entity	No	There appears to be a gap between IRO-001-4 and IRO-002-4 related to Operating Instructions. In COM-002-4, Operating Instructions are issued either as an oral two-party communication, multi-party burst communication, or written. IRO-002-4, R1, requires the RC to have voice communication facilities with TOPs, BAs and GOPs. IRO-002-4, R2, requires the RC to have data links with BAs, PCs, TPs, GOs, LSEs, TOPs, TOs and DPs. IRO-001-4 R2 states that TOPs, BAs, GOPs, TSPs, and DPs shall comply with RC Operating Instructions. The possible gaps lies in the fact the TSPs and DPs are not required to have voice communication facilities with the RC per IRO-002-4, which implies that the only method for communication of

Organization	Yes or No	Question 1 Comment
		Operating Instructions with TSPs and DPs would be in a written form. Please clarify if that was the intent of the SDT? In addition, TSPs are not required to have data links with the RC. With no required voice or data links what is the expectation for TSPs to receive Operating Instructions from the RC?
Response: The SDT has revised proposed IRO-002-4, Requirements R1 and R2. This should address your concerns. Please see responses to question 2. The SDT agrees and has removed Transmission Service Provider from Requirements R2 and R3. See summary consideration for revision.		
Georgia Transmission Corporation	No	(1) GTC does not believe that the DP should be an applicable entity to this standard. The RC would not direct a DP to perform Operating Instructions due to the proper chain of command. The RC would first direct the TOP. See RC section in the NERC Functional Model under System restoration actions "The Reliability Coordinator directs and coordinates system restoration with Transmission Operators and Balancing Authorities." Due to this proper chain of command, there is no reliability gap between the RC and the DP. The TOP, could further direct Operating Instructions during an Emergency to the DP per TOP-001-3. If the SDT does not remove the DP from applicability to this standard, then GTC recommends the following: (2) The current proposal for R2 as written could overly expose the DP to excess compliance obligations for routine switching operations performed on a daily basis which does not affect the reliability of the BES such as maintenance items, etc. The DP implement operating instructions on non-BES equipment on a routine basis, but the implementation of operating instructions on BES equipment, or non-BES equipment "affecting the reliability of the BES" is not very routine. GTC believes the intent of this requirement for the DP should complement COM-002-4 R6 relating to

Organization	Yes or No	Question 1 Comment
		Operating Instructions during an Emergency "affecting the reliability of the BES". The use of the NERC term "Emergency" would capture this intent. GTC proposes the language "[during an Emergency]" be added after "....shall comply with its Reliability Coordinator(s) Operating Instructions [ ] ".
Response: (1) The SDT has revised proposed IRO-002-4, Requirements R1 and R2. This should address your concerns. Please see responses to question 2. (2) See response to the Distribution Provider concern in (1) above. With respect to the second part of the second comment, the SDT believes Operating Instructions should be issued in an Emergency or to address or prevent situations that could lead to an Emergency. If a Reliability Coordinator issues an Operating Instruction to ensure the reliability of its Reliability Coordinator Area, then that Operating Instruction must be followed unless one of the reasons in Requirement R2 apply. The SDT believes the requirements as written are responsive to concerns raised by FERC in the NOPR.		
ReliabilityFirst		ReliabilityFirst submits the following comments for consideration: 1. Requirement R3 - ReliabilityFirst recommends there be a timeframe be added to the requirement stating the allotted time the Entity has to inform its Reliability Coordinator of its inability to perform the Operating Instruction. Absent a time frame, the reliability of the BES may be compromised if an Entity cannot perform Operating Instruction in a timely manner. ReliabilityFirst suggests the following for consideration. "Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator [within 30 minutes of receiving an Operating Instruction] of its inability to perform the Operating Instruction..."
Response: The SDT believes it is understood that entities should begin initiating actions per an Operating Instruction immediately and if the entity realizes they cannot implement the instructions for any of the reasons in Requirement R2, it should immediately notify the Reliability Coordinator. The SDT believes that Operating Plans and Operating Instructions may include a time line and that		

Organization	Yes or No	Question 1 Comment
a time line is not necessary, or appropriate, for a requirement. A generic time requirement in a requirement may actually prove to be detrimental to reliability. No change made.		
SERC OC Review Group	Yes	The SERC OC Review Group requests clarification on who “others” are for R1: “RC shall act, or direct others to act,” Suggestion: “directs others (as identified in R2) to act”. Current: “Each Reliability Coordinator shall act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.” Suggested: “Each Reliability Coordinator shall act, or direct others (as identified in R2) to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.”
Response: The “others” referred to in Requirement R1 are those entities listed in Requirement R2. No change made.		
Hydro One	Yes	R-10 requires TOPs to monitor facilities in neighboring TOP areas and is an overlap of an RC-wide area review responsibility.
Response: There is no Requirement R10 in this standard. The SDT believes the reference should be for proposed TOP-001-3 and points the commenter to question 7.		
Salt River Project	Yes	R3 requires an entity to cite one of the reasons in R2 for an inability to perform an Operating Instruction. SRP expresses concern over only permitting a predetermined list of rational for not performing an Operating Instruction. Situations may arise that do not fit nicely into one of the given reasons. IT is suggested to allow for other rational for not performing Operating Instructions.
Response: The SDT believes Requirement R2 adequately provides the criteria for a situation where an Operating Instruction cannot be complied with. However, the SDT agrees it is not necessary or beneficial to reliability to cite the reasons at the time of the event. The specific reason(s) why an entity was unable to perform an Operating Instruction would be discussed after the issue requiring action was resolved. The reason(s) would still need to be in accordance with those specified in Requirement R2. No change made.		

Organization	Yes or No	Question 1 Comment
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI supports comments posted by the SERC OC Work Group
Colorado Springs Utilities	Yes	
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	
PPL NERC Registered Affiliates	Yes	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
FirstEnergy	Yes	
ISO/RTO Standards Review Committee (SRC)	Yes	

Organization	Yes or No	Question 1 Comment
Peak Reliability	Yes	
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
Rutherford EMC	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Manitoba Hydro	Yes	
Exelon Ccompanies	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	R1 - N/AR2 and R3 - ATC agrees with the proposed IRO-001-4 Requirements R2 and R3.
PNMR	Yes	
David Kiguel	Yes	
PJM Interconnection	Yes	
Ameren	Yes	

Organization	Yes or No	Question 1 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Independent Electricity System Operator	Yes	
Hydro One	Yes	
INDN - Independence Power & Light	Yes	
NV Energy	Yes	
Response: Thank you for your response.		

2. Do you agree with the changes made to proposed IRO-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

Summary Consideration: The SDT has provided clarification to numerous concerns and made the following changes due to industry comments:

R1.

R2. Each Reliability Coordinator shall have data exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R4. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

R5. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and change "compliance investigations" to "compliance violation investigation" in Section 1.2 Compliance Monitoring and Enforcement Processes. To be consistent with the format of other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention (page 7). Requirements R1 and R2 appear redundant to the COM-001 Standard; suggest these requirements be deleted. R1 requires voice communication as opposed to the COM-001-2 requirement for the RC to utilize Interpersonal Communication, which is defined as "Any medium that allows two or more individuals to interact, consult, or exchange information." Is a RC supposed to have voice communication and

Organization	Yes or No	Question 2 Comment
		Interpersonal Communication, or does voice communication apply to both IRO-002 and COM-001? If this is the case, then these two requirements are redundant. R2 requires data links while the VSL utilizes data link facilities. We prefer the use of data link facilities. The use of facilities would imply that this is not a SCADA point by point requirement but an overall emplacement of equipment required to transmit data. It also helps address the concern that the requirement as written implies the data link is operational 24/7. The NERC Event Analysis Program has issued lessons learned where data communications between entities have been interrupted due to EMS issues. Finally, it would avoid any redundancy with the proposed IRO-010 R3 or IRO-014 R3. R3- System Operators should have authority to both approve and disapprove planned outages. From R3, "...maintenance of its monitoring and analysis capabilities." What is "its" referring to? The Rationale isn't clear on this either. R4- Suggest rephrasing R4 because the last phrase starting with word "including" is modifying the Facilities being monitored and not the type of exceedances being monitored for. Reword to "Each Reliability Coordinator shall monitor facilities, including sub-100 kV facilities when necessary and the status of Special Protection Systems in its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area." R5 contains some 'how, not why' language: "giving particular emphasis to alarm management and awareness systems, automated data transfers," which may, in fact, produce a lowest common denominator approach to EMS systems. A part of the Requirement is also redundant to COM-001: "over a redundant and highly reliable infrastructure." R5 could be improved to become performance oriented by removing ambiguous terms. For example, what is the measure of particular emphasis, and highly reliable? Also, does redundancy mean to have a Primary and Backup in which

Organization	Yes or No	Question 2 Comment
		case EOP-008 already requires this redundancy? We suggest rephrasing to: Each Reliability Coordinator shall have systems that provide Real-time situational awareness of the BES to its System Operators.
Response: Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure. The SDT agrees and has made the suggested changes. See summary consideration for revisions. The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT does not agree that Requirement R2 is redundant with proposed COM-001-2 as that standard is about 'persons' communicating and not data. No change made. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT believes that by having the authority to approve the System Operator can also implicitly cancel or deny an outage as well. No change made. "its" is used to imply ownership. In other words, the responsible entity is responsible only for its own "monitoring and analysis" capabilities. No change made. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision.		
FRCC Operating Committee (Member Services)	No	We recommend the removal of the Operations Planning horizon from this Standard. The Purpose of this Standard states "Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions." This would not apply in the Operations Planning horizon.

Organization	Yes or No	Question 2 Comment
Seminole Electric Cooperative, Inc. Florida Municipal Power Agency		R1 - This requirement is duplicative with currently enforced COM-001-1.1 R1 and future COM-001-2 R1. The communication with GOPs should be done through BA because the BA/TOP should be aware of actions being taken in regards to generation. The term “voice communications” should be singular. R2 - The term “data links” lends to the idea of an electronic submittal. PCs, TOs, GOs, LSE, DPs and TPs do not need to provide real time data. We recommend the language be modified to allow for data links with BAs and TOPs. The requirement could also state that TOs, GOs, GOPs, LSEs, and DPs shall provide, or have provisions for, the data via their host BA/TOP. We recommend PCs and TPs be removed from this requirement. R3 - The language “to approve” does not seem to cover the full spectrum of authority needed by the RC. We recommend the following language: ”Each RC shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.” R4 - To eliminate confusion, we recommend creating two requirements with the following language: Each Reliability Coordinator shall monitor Facilities, and identified sub-100 kV facilities, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. The addition of Special Protection Systems to this requirement eliminates the need for SPSs within the new Real-time Assessment term definition. R5 - This requirement does not seem to be measurable. What does “over a redundant and highly reliable infrastructure” mean? What is an acceptable level of synchronism and reliability? How are these terms going to be measured?

Organization	Yes or No	Question 2 Comment
		We recommend adding an additional requirement stating: "Each RC shall monitor identified phase angle limitations within its RC Area." This will eliminate the need for the phase angle language within the new Real-time Assessment term definition.
Response: The SDT believes the Time Horizons are appropriately used. Requirements R1, R2, and R3 deal with information that could be used to run various studies including Real-time Assessments and Operational Planning Analyses as well as planned outages. These occur in the Operations Planning Time Horizon. No change made. The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT believes that by having the authority to approve the System Operator can also implicitly cancel or deny an outage as well. No change made. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision. The SDT does not believe a new requirement is needed to address 'identified' phase angle limitations as it is correctly handled by including it in the Real-time Assessment and Operational Planning Analysis definitions. No change made.		
MRO NERC Standards Review Forum	No	R5. The NSRF does not agree with the ambiguous wording of "over a redundant" and "highly reliable infrastructure". EOP-008-1, R3 requires an RC to have a backup control center facility not dependent on the primary control center. This is the same type of required items within R5. Recommend deleting "over a redundant" in order to remove the similar language and remove the possibility of double jeopardy. Concerning the word of "highly reliable infrastructure", we do not believe that an RC would utilize "slightly reliable infrastructure". This ambiguous wording will be a compliance night mare as it will always be subjective in nature. Recommend deleting "highly reliable infrastructure". A simple recommendation would be to remove the

Organization	Yes or No	Question 2 Comment
		wording of “over a redundant and highly reliable infrastructure” and replace it with “over a system that is not impacted by a single point of failure”.
Response: The SDT has deleted the term ‘and highly reliable’ as it is unmeasurable. See summary consideration for revision.		
SERC OC Review Group Associated Electric Cooperative, Inc. - JRO00088	No	The SERC OC Review Group has concerns adding TP, PC, and DP to real-time data requirements to R2. DP provides info to TOP who then provides info to RC. Neither the TP nor PC provides the RC real time data, thus not requiring a data connection.
Response: The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision.		
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 Georgia System Operations Georgia Transmission Corporation	No	Although the SDT’s Rationale indicates there is no redundancy with proposed requirements in this Project 2014-03, Southern believes Requirements 1 and 2 are redundant with existing effective COM-001-1 R1 and future mapping of this requirement to future enforceable standards. Southern also notes that COM-002-2 R1 is the corresponding requirement for the TOPs and BAs to have both voice and data links with appropriate RCs, BAs, and TOPs. Southern suggests that these existing standards and other industry approved future enforceable standards addresses any reliability gaps. Southern also suggests that R2 is redundant with both the existing and proposed IRO-010 in this project. IRO-010 already requires the RC to provide data specifications to the entities listed in R2 and requires such entities to provide the data specified by the RC. Southern recommends that both R1 and R2 be removed. As an alternative to removing R2, Southern suggests that TPs/PCs be removed from R2 because these functional entities were specifically added to IRO-010 for purposes of providing UFLS and UVLS data to RCs. They do not need to be in both standards. The proposed Requirement 3 needs to be revised to clarify that it is only addressing monitoring and analysis capabilities and not planned outages and maintenance of BES elements. As currently drafted, one could interpret it as planned outages of BES

Organization	Yes or No	Question 2 Comment
		element and maintenance of monitoring and analysis capabilities, and Southern does not think that is the intent of the SDT. Southern suggest changing the requirement to, "Each Reliability Coordinator shall provide its System Operators with the authority to approve the following: R3.1. Planned outages of its monitoring and analysis capabilities.R3.2. Maintenance of its monitoring and analysis capabilities. Requirement 4, as proposed, does not indicate how far into the neighboring system a RC should monitor. Southern suggest incorporating language referencing the RCs wide area view methodology and language specifying that it should include sub-100 kV facilities, "as deemed necessary by the RC" (similar to the language used in the proposed IRO-010-2 R1.1). Southern proposes the following verbiage to add clarity to the requirement: "Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas consistent with its wide-area view methodology to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area , including sub-100 kV facilities, as deemed necessary by the Reliability Coordinator, and the status of Special Protection Systems, to make this determination."
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT believes that proposed IRO-002-4 deals with data link facilities proposed while IRO-010-2 spells out what specific data is needed. Therefore the SDT does not believe there is any redundancy. No change made. The SDT believes the language is clear as written and that the suggested change does not add clarity. No change made. The SDT believes that the requirement as written provides for each Reliability Coordinator to use its professional and technical judgment to determine what it needs to monitor and that this is the correct path to take for system reliability. However, the SDT has changed the wording of the requirement in response to other comments. See summary consideration for revision.		

Organization	Yes or No	Question 2 Comment
Dominion	No	Dominion does not agree with requirement 1 as it is very similar to COM-001-2, R1 and because we do not agree that the Reliability Coordinator should be required to have direct communications facilities with Generator Operators within its Reliability Coordinator Area. We believe that the Interpersonal Communication capability developed pursuant to COM-001-2 could allow the Reliability Coordinator to communicate to Balancing Authorities or Transmission Operators in its Reliability Area, and requiring that entity to communicate directly with other operators and users (including DP, GOP and LSE). Dominion does not agree with requirement 2 as written. While we agree that each Reliability Coordinator should have data links with each Balancing Authority and Transmission Operator within its reliability area and with neighboring Reliability Coordinators, we do not agree that it should be required to have data links with all Generator Owners, Generator Operators, Load-Serving Entities Transmission Owners, and Distribution Providers in its reliability area. We believe this requirement should NOT apply if the Reliability Coordinator’s documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments (pursuant to Proposed IRO-010-2, Requirements R1 and R3, part 3.3) allows for the data to be provided via data links with a Balancing Authority or Transmission Operator within its reliability area. We can agree that data links with Planning Coordinators or Transmission Planners be required only if the Reliability Coordinator identifies the need for data pursuant to IRO-010-2. Dominion does not see the need for Requirement 3. IRO-001-4@R1 already requires the RC to act or direct others to act, to ensure the reliability of its Reliability Coordinator Area. This requirement should be included in whatever authority document the RC provides to its System Operators relative to the function of Reliability Operations and the Functional Entity of Reliability Coordinator (per Functional Model V5). Dominion does not agree with R4 as written. We are opposed to the inclusion of the phrase “including sub-100 kV facilities”. We would prefer to modify the requirement

Organization	Yes or No	Question 2 Comment
		to read "Each Reliability Coordinator shall monitor BES Facilities, and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area." It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. 2nd citing of R4 in the mapping document Dominion does not agree with R4 as written. We are opposed to the inclusion of the phrase "including sub-100 kV facilities". We would prefer to modify the requirement to read "Each Reliability Coordinator shall monitor BES Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area and the status of Special Protection Systems in its Reliability Coordinator Area." It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process.
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT does not believe approval of planned outages and maintenance of its own monitoring and analysis capabilities falls under the realm of acting or directing others to act as this authority more governs issuing Operating Instructions to other entities. No change made. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. The mapping document has been updated accordingly.		
Duke Energy	No	R1: (1) Duke Energy believes that this requirement is duplicative with the currently enforced COM-001-1.1 and the future COM-001-2 and suggest removing this

Organization	Yes or No	Question 2 Comment
		requirement or clarify the need to have this requirement in conjunction with the COM-001 requirements. (2) Per the Functional Model, the RC directly communicates with the BA and TOP only and should have voice communications facilities with those Functional Entities. Communications to the GOP would come from either the TOP or BA. R2: The RC should only be required to have data links with the TOPs and BAs only. Data links from the GO, TO, GOP, LSE and DP would come from their host TOP or BA. The RC could have a process or provision in place to receive the data from those entities via the host TOP or BA in their RC area. Again, this is out of scope with the Function Model. R3: - Duke Energy suggests the following language: "Each RC shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools." The removal of System Operators is necessary in the context of this requirement. Per the NERC definition, System Operators are the individuals "who operates or directs the operation of the Bulk Electric System (BES) in Real-time." System Operators work in a real-time environment and thus is in direct conflict with the use of the Operations Planning Time Horizon (next day to seasonal) in this requirement. In addition, we believe the RC should have the authority to approve, deny or cancel these types of outages in R3, not just the individual System Operators. There can be instances where a program tool used to perform a next-day study analysis could be requested to be taken out of service for maintenance and the RC needs to have the authority to deny that request. R4: Duke Energy believes that this requirement should be separated into two different requirements and suggests the following language: "Each Reliability Coordinator shall monitor Facilities, and identified sub-100 kV facilities, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability

Organization	Yes or No	Question 2 Comment
		Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area." We believe separating this into two requirements will provide better clarity on the expectations that should be monitored by an RC. R5: Duke Energy has concerns that this requirement, as written, is not measurable. We seek clarity on the phrase "over a redundant and highly reliable infrastructure". It is not clear to us what is considered an acceptable level of synchronism and reliability, and therefore have concerns how this will be measured. We suggest rewording this requirement for clarity or removing from this standard.
Response: (1) The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. (2) The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. R3. The SDT placed the authority on the System Operator since they are the ones using and monitoring the real time tools and the ones who need to have the control, not the entity. This should not place a burden on the System Operator. The Operations Planning Time Horizon is captured for planned maintenance and outages. The SDT believes that by having the authority to approve the System Operator can also implicitly cancel or deny an outage as well. No change made. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision.		
Bureau of Reclamation	No	Reclamation believes that, like under IRO-002-2, Reliability Coordinators should be able to have data links with Transmission Operators and Balancing Authorities, who in turn communicate with Generator Operators and Distribution Providers. Reclamation believes that Reliability Coordinators should be able to elect this model so that Transmission Operators and Balancing Authorities are aware of all instructions regarding generation and transmission that are issued in their control areas.

Organization	Yes or No	Question 2 Comment
Response: The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision.		
SPP Standards Review Group	No	Requirement R1 is redundant in that Requirement R1 of COM-001-2 already requires the Reliability Coordinator to have Interpersonal Communication capabilities. Therefore, this requirement should be eliminated for Paragraph 81 considerations. Requirement R2 requires the Reliability Coordinator to have data links with several non-traditional functional entities that are not normally associated with the exchange of Real-time data. Data links have specific connotations associated with specific equipment such as ICCP, etc. We would suggest that the language in this requirement be revised to parallel the language in IRO-010-2, Requirement R2. This also parallels the language in the COM standards. We would go on to suggest that since the requirement for the data to be supplied is contained in IRO-010-2, this specific requirement is redundant and too prescriptive in that it addresses how the exchange of data is to be accomplished rather than the real objective of exchanging data which is addressed in IRO-010-2. Requirement R5 requires a 'redundant and highly reliable infrastructure' for the exchange of data. This appears to be redundant with EOP-008-1, Requirement R6 which already calls for backup control centers which are not dependent upon the primary site for functionality. Since redundancy is already required by EOP-008, there is no need for Requirement R5.
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision.		

Organization	Yes or No	Question 2 Comment
The SDT believes that proposed IRO-002-4 deals with data link facilities proposed while IRO-010-2 spells out what specific data is needed. Therefore the SDT does not believe there is any redundancy. No change made. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision.		
ACES Standards Collaborators	No	(1) The list of entities that the RC should have data links with should be reduced to include only operational entities. Inclusion of Planning Coordinators does not make sense because they have no real-time data to provide. We question inclusion of equipment owners such as TOs and GOs since the associated operational entities are already included. The associated operational entities should be able to provide any data that the equipment owner can provide. (2) Requirement R4 is problematic as written because it implies that sub-100 kV transmission equipment are Facilities (i.e. the NERC defined term). They may be if they are part of the BES Otherwise, they are not. A simple solution would be to remove the clause "including sub-100 kV facilities needed to make this determination". If these sub-100 kV facilities are needed they should probably be part of the BES and will be covered by the NERC defined term "Facilities" making the clause superfluous. (3) For Requirement R5, we recommend removing the phrase "highly reliable." This is subjective, vague, and does not belong in a reliability standard. Redundancy should provide the requisite reliability for monitoring systems. If the drafting team believes that RCs should have tertiary redundancies or meet some service level, then state that as a requirement. (4) For Requirement R5, we also question the term "giving particular emphasis to alarm management" because it is ambiguous, vague, and not measurable. (5) We question the binary nature of the VSL tables and ask the SDT to consider graduated treatment of violations.
Response: (1) The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision.		

Organization	Yes or No	Question 2 Comment
(2) The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. (3) The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision. (4) While the SDT understands that the commenter may feel that the term is vague, the SDT believes that it places emphasis on the condition and allows for professional and technical judgment to be employed to satisfy the requirement thus allowing for maximum flexibility on the part of individual entities to tailor the solution to best fit its individual needs. No change made. (5) See response to Q14.		
ISO/RTO Standards Review Committee (SRC)	No	R1 and R2 appear redundant to the COM-001 Standard; suggest deleting these. We agree that a better distinction is required between voice and data requirements. However it should be added to COM-001 or remove COM-001. R4: The "Rationale" for the new R4 as being responsive to the NOPR where the Commission indicates "the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator...." However, other functional entities are not "backed up" and EOP-008 now contains backup provisions for reliability: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost." R5 contains some 'how, not why' language: "giving particular emphasis to alarm management and awareness systems, automated data transfers," which may, in fact, produce a lowest common denominator approach to EMS systems and a part of the Requirement is also redundant to COM-001: "over a redundant and highly reliable infrastructure." R5 - Terms like "particular emphasis" and "Highly reliable" are not defined terms. They should be deleted or the requirement should include defined values for them for clarity.

Organization	Yes or No	Question 2 Comment
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. While the SDT understands that the commenter may feel that the terms are vague, the SDT believes that it places the proper emphasis on the conditions and allows for professional and technical judgment to be employed to satisfy the requirement thus allowing for maximum flexibility on the part of individual entities to tailor the solution to best fit its individual needs. No change made.		
Peak Reliability	No	R1: What is the definition of “voice communication facilities”? Is a list of phone numbers and a phone system sufficient? R2: “Data link” is not a defined term. “As required for reliable operations in the Interconnection” should be added to R1 and R2. RC data links with TPs, PCs, GOPs, LSEs, and DPs are not required for reliable operations. It is sufficient for the RC to have data links with BAs and TOPs, and get TP/PC/GOP/LSE/DP data from BAs and TOPs. R3: The word “approve” should be changed to “disapprove”. System Operators may not always have the understanding of the maintenance to actively “approve” it, but their authority should be to disapprove planned tool outages if they will adversely impact real-time operations or if System Operators need more time to assess a tool outage. R4: The way it is phrased gives risk for misunderstanding. Is the Requirement that RCs must “monitor” the status of RAS? Or is the Requirement that the RC must understand/model the impact of the RAS so that the RC knows the status of any SOL or IROL and whether or not it is being exceeded given the expected RAS action? The

Organization	Yes or No	Question 2 Comment
		way it reads it seems the RC is only required to “monitor” the RAS, which to Peak means have awareness of the arming status and know when the RAS operates. Also, this Requirement is unclear whether the RC needs to monitor facilities in adjacent RCs only to the extent that such facilities actually affect SOLs/IROLs? Adding the phrase “as needed” to “and neighboring Reliability Coordinator Area” adds more clarity.
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT believes that the suggested change is unnecessary. The Reliability Coordinator should establish facilities with the entities listed as they are the ones required for reliable operations. No change made. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. R3. The SDT felt that by having the authority to approve the System Operator also could implicitly cancel or deny an outage as well. No change made. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision.		
Ingleside Cogeneration LP	No	Requirement R4 calls for the Reliability Coordinator to monitor certain sub-100 kV facilities that to ensure operational reliability. Although ICLP agrees with the fundamental premise, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new Definition of the BES. This process was developed precisely for this reason - and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. Without this limitation, we can see that the standard will be applied

Organization	Yes or No	Question 2 Comment
		unevenly across Reliability Coordinators; which works against the fundamental intent of reliability standardization.
Response: The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision.		
NIPSCO	No	1. In R5 the term "highly" reliable is used. Please define "highly". 2. In R2 "data links" needs to be defined, as well as the context in which they are to be used (what are the data links for?). 3. Should R1 and R2 be contained in the COM standards, as opposed to IRO-002? 4. R3 should be included in IRO-017, as it is an outage coordination requirement.
Response: 1. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision. 2. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. 3. The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. 4. Requirement R3 is only applicable to a Reliability Coordinator's System Operators having the authority to approve planned outages and maintenance of its own monitoring and analysis capabilities. It is not associated with interconnected transmission system outages which is the subject of proposed IRO-017-1. No change made.		
David Kiguel	No	R1: The requirement of voice communications facilities is a matter to be addressed by COM standards. Inclusion in IRO-002-4 could introduce compliance issues (double jeopardy). R4: Requires RC to monitor facilities in neighboring Reliability Coordinator Areas i.e. outside of its own.

Organization	Yes or No	Question 2 Comment
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. R4. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision.		
PJM Interconnection	No	Specific to R2, PJM does not agree there needs to be data link requirements between the RC and the PC, TP, LSE and DP to monitor and control the electric system in real-time. Both the TP and PC do not have the real-time data necessary to monitor the system, and therefore, data links are not needed. Specific to the LSE and DP, their real-time data is provided directly to their TOP or TO.
Response: The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision.		
Hydro One	No	R-1 contains what appears to be a redundant P-81 type of issue between what is in COM-001-2 and this standard- Interpersonal Communication vs. Voice Communication. These requirements could introduce a double jeopardy issue for non-compliance and should be revisited by the drafting team and further explanation provided prior to support.
Independent Electricity System Operator	No	We agree with all the requirements except R1. Requirement R1 appears to be largely redundant with Requirement R1 of COM-001-2. Requirement R1 of COM-001-2 requires each Reliability Coordinator to have Interpersonal Communication capability with the TOP and BA within the RC area and with each adjacent RC within the same Interconnection. By definition, Interpersonal Communication is “Any medium that allows two or more individuals to interact, consult, or exchange information.” The difference between the two requirements appears to be the omission of Generator Operator in COM-001-2, which can be added to totally eliminate the redundant IRO-002-4 R1. We suggest the SDT consider presenting this option to the Standards Committee to initiate appropriate actions to avoid adding a P81 candidate.

Organization	Yes or No	Question 2 Comment
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions.		
INDN - Independence Power & Light	No	Requirement R1 is very similar to Requirement R1 of COM-001-2 which requires the Reliability Coordinator to have Interpersonal Communication capabilities with the exception that COM-001-2 does not include a requirement for RC to have comm links with GOPs. For Paragraph 81 considerations, the two standards should be reconciled such that only one requirement is needed. INDN supports the comments submitted by Southwest Power Pool regarding Requirement R2. Requirement R5 requires a 'redundant and highly reliable infrastructure' for the exchange of data. There is some confusion as to whether this statement refers to redundant circuits providing data to a Control Center EMS or refers to an independent backup center as required by EOP-008. If in fact the infrastructure referenced is a backup center, then R5 is redundant and should be eliminated from the standard. Clarification is needed to resolve this question.
Response: 1. The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. 2. Please see response to Southwest Power Pool. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision.		
Electric Reliability Council of Texas, Inc.	No	ERCOT does not agree with the rationale for deleting R2 of IRO-002-3. EOP-008 is an emergency operating plan for loss of primary control center functionality. Most instances of the situations that R2 applied to are not emergency situations, but for

Organization	Yes or No	Question 2 Comment
		having alternative means of accomplishing required reliability tasks during the timeframe that analysis tools may be unavailable.
Response: The SDT felt that Requirement R2 of proposed IRO-002-3 was vague and decided to draft Requirement R3 of proposed IRO-002-4 which gives the responsibility and authority for any planned maintenance or outages of monitoring/analysis tools to be approved by the System Operator. No change made.		
Texas Reliability Entity	No	1) R4: Recommend replacing "to determine any potential System Operating Limit..." with "to determine any existing (pre-Contingency) and potential (post-Contingency) System Operating Limit... ". This change would be consistent with the terminology used in the proposed definition of Real Time Assessment. 2) R5: Recommend establishing a bright line criteria, such as: "fully redundant" and "a highly reliable infrastructure with end-to-end availability in each system of 95% or greater." Also recommend technical guidance to provide more clarity on the intent for monitoring alarm management and awareness systems. As written, R5 does not meet the quality criteria of clear and unambiguous language (as identified in NERC's "Acceptance Criteria of a Reliability Standard: Quality Objectives", item 8). From a compliance and enforcement perspective it is difficult to measure "giving particular emphasis" and "highly reliable infrastructure".
Response: 1) The SDT feels that pre-Contingency or post-Contingency are contained in the definitions of SOL and IROL and adding that language would create redundancy with the current language of monitoring SOL and IROL exceedances. No change made. 2) The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision. While the SDT understands that the commenter may feel that the terms are vague, the SDT believes that it places the proper emphasis on the conditions and allows for professional and technical judgment to be employed to satisfy the requirement thus allowing for maximum flexibility on the part of individual entities to tailor the solution to best fit its individual needs. No change made.		

Organization	Yes or No	Question 2 Comment
NV Energy MidAmerican Energy	No	R2: Regarding data links with a variety of entities, we see no reliability rationale for requiring data links with Planning Coordinators, Transmission Planners, Load Serving Entities, or Distribution Providers. With the first two, there is no call for real time data; for the others the data for LSE and DP entities normally routes through the host TOP or BA, which is where the data link requirement should solely reside. Recommend deletion of "Load Serving Entities, or Distribution Providers." R3: As written, it is unclear whether the authority to approve planned outage and maintenance of its monitoring and analysis capabilities extends to RC personnel other than the Operators alone. Also, the authority to approve does not literally mean that the RC Operator "must" approve; therefore, there may be an unintended consequence that such maintenance work could be performed without RC approval. R5: The phrase "over a redundant and highly reliable infrastructure" is rather imprecise. Suggest replacing this phrase with "over a system that is not interrupted by a single point of failure".
Response: R2. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. As written, and as the SDT intended, the requirement applies only to System Operators. If maintenance work was performed without the approval of the System Operator, the entity would be in violation of this requirement. No change made. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	
PPL NERC Registered Affiliates	Yes	

Organization	Yes or No	Question 2 Comment
Bonneville Power Administration	Yes	
Rayburn Country Electric Cooperative	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Exelon Companies	Yes	
Xcel Energy	Yes	
PNMR	Yes	
Consumers Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Salt River Project	Yes	
Response: Thank you for your response.		

3. **Do you agree with the changes made to proposed IRO-008-2? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration:

Several commenters noted the discrepancy between the language in the Rationale Box for Requirement R6 and the requirement itself. The language in the Rationale Box was modified to bring it in line with the requirement.

Several commenters pointed out what they felt was a potential discontinuity between the 30-minute criterion in Requirement R5 and the 2-hour allowance provided in approved EOP-008-1, Requirement R5. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement. Specifically, approved EOP-008-1 requirements address:

1.2.1 Tools and applications to ensure that System Operators have situational awareness of the BES.

1.6.2 Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of 'Real-time Assessment' do not specify the manner in which an assessment is performed nor do they preclude Reliability Coordinators and Transmission Operators from taking 'alternative actions' and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on its Reliability Coordinator to perform a Real-time Assessment or even review its Reliability Coordinator's Contingency analysis results when its capabilities are unavailable and vice-versa. The SDT did modify the requirement language to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts.

Many commenters posed questions regarding daily Operating Plans. Although no changes were made to the requirements as a result of those comments, the SDT offered the following to clarify the intent of the SDT. An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Analysis or a Real-time Assessment. As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the Operational Planning Analysis. When a Reliability Coordinator performs an Operational Planning Analysis, the analysis may reveal instances of possible SOL and IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for the day-to-day SOL or IROL exceedances identified in the Operational Planning Analysis are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of 'the Operating Plan document' for compliance purposes.

Numerous commenters suggested combining Requirement R2 with other requirements or simply deleting it altogether. The SDT chose to delete it as indicated below.

Several commenters suggested language changes for Requirement R7 which the SDT subsequently deleted in lieu of proposed IRO-001-4 Requirement R1.

Other comments suggested modifying the 'NERC registered entity' terminology in Requirement R4 and the use of the term 'Reliability Coordinator Wide Area' in Requirement R1. Both of these terms were modified.

The rest of the comments received were single comments and are addressed individually below.

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

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

R2.

R3. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

R4. Each Reliability Coordinator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s).

R5. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

R7.

Data retention: Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R4, R6 through R8 and Measures M1 through M4, M6 through M8 for a rolling six month period for analyses, the most recent 90 days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R5 and Measure M5 for a rolling 30 calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	Under the section "Definitions of Terms used in the Standard" it is stated that there are no new or revised definitions proposed in this standard revision, but the standard refers to a revised definition of "Operational Planning Analysis". Suggest keeping the Purpose of IRO-008-1. The proposed Purpose in IRO-008-2 does not adequately introduce what the performed analyses and assessments are performed on.
Response: The SDT agrees and has made the suggested change. The SDT does not believe that the suggestion adds clarity. No change made.		

Organization	Yes or No	Question 3 Comment
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	As defined, the term “Operating Plan” refers to a formal document or plan must be submitted. There are existing other requirements and processes in place within our region that provide the necessary data (via automated tools) to perform the next-day study. Requiring a submission of an “Operating Plan” would require the data to be manually entered and result in additional man-power usage with no benefit to reliability. We recommend the following language: ”Each Reliability Coordinator shall review the operating data for next-day operations provided by its Transmission Operators and Balancing Authorities.” R3 - This requirement implies a formal “Operating Plan” must be produced each day. See comments for IRO-008-2 R2 above. We recommend the following language: ”Each Reliability Coordinator shall document the coordination of actions for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the data for the next-day provided by its Transmission Operators and Balancing Authorities.” R4 - What does “impacted” mean and why is it not limited to entities who are required to take action (TOPs, BAs, GOPs, etc.)? R6 - Is this meant to refer to the Operating Plan developed in R3? Need clarification. Rationale for R6 discusses use of the term Emergency, yet the term is not used in R6 or R7. The words “as indicated in its Operating Plan” add no value to the statement requiring notification to the named entities. Recommend deletion. R7 - Change “to deal with” to “to prevent or mitigate.” Add clarification because the TOP and BA are also issuing Operating Instructions. It should be clear that the RC is a back stop for TOP and BA. R8 - Same as R6. Delete “as indicated in its Operating Plan”.

Organization	Yes or No	Question 3 Comment
		Compliance section 1.3 - Data Retention: Recommend changing “the most recent three months for voice recordings” to “90 days” to eliminate disparity with non-30 day months. This also will allow automation of deletion processes. It will also make the second paragraph match the third paragraph which requires 90 days for R5 voice recordings.

Response: Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator’s disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes. No change made.

R3 – The response to your comment concerning Operating Plan above addresses your concern for the development of a daily Operating Plan in Requirement R3. No change made.

Organization	Yes or No	Question 3 Comment
R4 - Impacted goes beyond the concept of those entities that have an active role to play in the Operating Plan. It also includes those entities which may not have an active role to play in the plan but are still impacted by the given operating condition. For example, an entity may have Load impacted by a given situation and the only available option that entity may have is to shed that Load. But if the plan doesn't call for that entity to shed the Load, then the entity doesn't have an active role in the plan but is still impacted by the situation and therefore is deserving of notification. However, the SDT has deleted 'NERC registered' due to comments received. See summary consideration for revision. R6 - Yes, the Operating Plan is the Reliability Coordinator's plan developed in Requirement R3. The 'its' is intended to point back to the Reliability Coordinator developing the plan. No change made. The 'Emergency' references in the Rationale Box for Requirement R6 have been deleted for consistency. The phrase 'as indicated in its Operating Plan' limits the notification of other Reliability Coordinators to only those identified in a Reliability Coordinator's Operating Plan. Otherwise, all other Reliability Coordinators would have to be notified which would be excessive. No change made. R7 – The SDT has deleted Requirement R7 as duplicative of proposed IRO-001-4, Requirement R1. See the summary consideration for the revision. Regarding your comment requesting clarification in the standard because the Transmission Operator and Balancing Authority also issue Operating Instructions, it is true that overlap does exist between the Reliability Coordination and Transmission Operator roles as well as between the roles of the Reliability Coordinator and the Balancing Authority. However, the clarification for that functionality is found in the Functional Model not in the reliability standards. The IRO standards are Reliability Coordinator based. Transmission Operator actions are covered in TOP standards. Likewise, the BAL standards, as well as some TOP standards, cover the requirements for Balancing Authorities. While the roles of the Reliability Coordinator and Transmission Operator are very similar, the scopes are considerably different. The Transmission Operator is responsible for reliably operating within its Transmission Operator Area whereas the Reliability Coordinator is responsible for a wide-area view which may encompass several Transmission Operator Areas. Both functions have the authority to direct other functional entities within its respective area to ensure reliable operations. A similar situation exists between the Reliability Coordinator and the Balancing Authority. It takes a shared, coordinated effort among all three entities to maintain reliability. No change needed with the deletion of the requirement. R8 – See our response to your comment regarding deleting the phrase 'as indicated in its Operating Plan' in R6 above. The SDT has updated the Compliance section with the latest approved language.		

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Forum	No	The NSRF does not concur with 1) the RC having Operating Plans for next day operations (per R2) as stated in TOP-002-4, R5 requires Operating Plans for each component of R4. Note that Operating Plans is defined as a DOCUMENT that identifies a group of activities... Plus 2) the notification of NERC Registered Entities identified in those plans. The NSRF does not know, for example, how having a requirement to inform someone of an Interchange schedule that they established with you, how this promotes system reliability. Having a day ahead Operating Plan should assist the BA in tomorrow's operations. But notifying impacted NERC registered entities is not conducive. PJM, SPP, MISO, etc. are registered BAs and they would be required to have an Operating Plan every day that will restate generation resource commitments demand patterns and reserve requirements. R5 should be deleted since the IERP only recommends this and it is not a FERC directive or remove Operating Plans and replace with "plans". R5, see question 11 concerning the 30 minute threshold
Response: 1) The Reliability Coordinator is not required to have such an Operating Plan as in proposed TOP-002-4. The Reliability Coordinator is required to have an Operating Plan per Requirement R3 of proposed IRO-008-2. The requirements that you mention in Requirements R4 and R5 are in proposed TOP-002-4 and are intended for the Balancing Authority not the Reliability Coordinator. An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration		

Organization	Yes or No	Question 3 Comment
process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes. No change made. 2) The essence of Requirements R4 and R5 in proposed TOP-002-4 is that Parts 4.1-4.4 should be considered by the Balancing Authority in the development of its Operating Plan for the next-day. If in the development of that plan, the Balancing Authority determines that the interchange schedule mentioned may need to be modified to address a given situation, then the Balancing Authority must notify you of the potential change such that you can be prepared to make the change. No change made. The SDT has modified the notification requirement in Requirement R4 by deleting the qualifier 'NERC registered'. There may be entities needing notification other than Balancing Authorities and Transmission Operators which the Reliability Coordinator normally communicates with. There may be situations where all of these entities are not specifically NERC registered, especially in Canada. See the summary consideration for the revision. R5 – The SDT was charged with considering a number of factors in its deliberations regarding the TOP/IRO package of standards. One of those factors was the directives issued by FERC in the NOPR. Another was the recommendations of the IERP. Both were taken to heart. The inclusion of Requirements R4 and R5 in proposed TOP-002-4 is intended to be a continuation of the separation of responsibilities for the Balancing Authority and Transmission Operator which had not appeared in previous versions of the standards. You will notice a considerable paralleling between the Transmission Operator and Balancing Authority as well as between the Transmission Operator and Reliability Coordinator. That being the case, Requirement R5 will not be deleted. (See our response in 1) above to your suggested proposal to delete R5.)		

Organization	Yes or No	Question 3 Comment
The SDT believes your reference to Question 11 concerning Requirement R5 is actually a reference to your response to Question 7. Please see our response to your comments in Question 7.		
Colorado Springs Utilities	No	1. R6 rationale says that "exceedance" was changed to "emergency" but the standard shows no change. 2. In R6 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities. 3. In R8 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities.
Response: 1. The Rationale Box for Requirement R6 has been changed for consistency. See the summary consideration for the revision. 2. & 3. – Timing requirements requested for Requirements R6 and R8 are already provided for in other standards. For example, if an IROL is exceeded, the applicable entities must act to mitigate the exceedance within the IROL's T_v (approved IRO-009-1 Requirement R4 and proposed TOP-001-3 Requirement R12). Similar requirements are provided for SOLs in proposed IRO-008-2 Requirement R7 and proposed TOP-001-3 Requirement R14 and the associated SOL whitepaper. The standards specify that applicable entities must operate within SOLs and IROLs. To comply with these standards timely notifications of all impacted entities must be made. No change made.		
SERC OC Review Group Associated Electric Cooperative, Inc. - JRO00088	No	1) In R6, the wording does not reflect the changes in the rationale. 'Exceedance' has not been replaced with 'emergency'. Did this change occur as result of multiple revisions in the draft? Current: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area." Suggested: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results

Organization	Yes or No	Question 3 Comment
		of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) emergency within its Reliability Coordinator Wide Area." 2) In the R5 VSLs, there is concern that the bandwidth between "lower" and "severe" VSL is only 15 minutes. Suggestion: expand bandwidth. 3) In R8, replace "prevented or mitigated" with "addressed". Current: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated." Suggested: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been addressed."
Response: 1) The Rationale Box for Requirement R6 has been changed for consistency. See the summary consideration for the revision. 2) Please refer to Question 14 for the SDT's responses to VSL comments. 3) The proposed wording change introduces ambiguity into the requirement. The existing wording is clear and straight forward in that a potential exceedance has been prevented or an actual exceedance has been mitigated. No change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	No	By the various uses of "Operating Plan" in Requirements 1 through 8, does the SDT consider this to be a single continuously updated operating plan or does the SDT expect an Operating Plan to be developed for next day assumptions which then transitions into a different operating plan when a real time condition is observed? Southern believes IRO-008-2 Requirement 2 will pose an administrative burden on the Reliability Coordinator as it is currently worded as it will require RCs to produce

Organization	Yes or No	Question 3 Comment
Company Generation; Southern Company Generation and Energy Marketing		an email response to all TOP and BA operating plans stating "reviewed". RCs are required to have a coordinated Operating Plan considering the Operating Plans provided by its TOPs and BAs in the proposed R3. In order for the RC to develop an Operating Plan, as required by R3, the RC must review its TOPs and BAs plans; therefore, Southern recommends removing requirement R2. As mentioned above, the use of Operating Plan in R6 is confusing. Does the SDT consider this to be a single continuously updated Operating Plan or does the SDT expect this to have been an Operating Plan developed for next day assumptions which then transitions into a different Operating Plan when a real time condition is observed? Also, as currently drafted, R6 is very confusing. Southern proposes rewording R6 to move the "as indicated in its Operating Plan" statement to the end to add clarity and eliminate confusion. "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area as indicated in its Operating Plan." For R7 and R8, consider the example where the RC and a TOP see a potential SOL in their real time assessments and coordinate with one another on a post contingency plan to address the issue. As time passes and system conditions change, the contingency issue no longer exists. These requirements create an administrative burden on RCs to notify the TOP if the contingency issue has subsided without ever having to implement a plan. A more realistic requirement would be for the RC to notify the TOPs/BAs that are having to reconfigure their system or re-dispatch generation to resolve an SOL issue when the SOL has been prevented or mitigated. Southern suggests rewording R7 and R8 to remove the administrative burden of notifications when no action was taken by a TOP/BA.

Organization	Yes or No	Question 3 Comment
Response: R1-R8 – An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes. No change made. R2 – Based upon your and other comments the SDT proposes to delete Requirement R2 as it is duplicative with Requirement R3 which requires the Reliability Coordinator's Operating Plan to be coordinated with the Operating Plans provided by its Balancing Authorities and Transmission Operators. That plan cannot be coordinated without reviewing the plans of the Balancing Authorities and Transmission Operators within the Reliability Coordinator's Area. See the summary consideration for the revision. R6 – Regarding your comment on Requirement R6 and Operating Plan, please refer to our response to your concern about Operating Plan in Requirements R1-R8 above.		

Organization	Yes or No	Question 3 Comment
R6 – Regarding your suggested wording for Requirement R6, the phrase 'as indicated in its Operating Plan' limits the notification of other Reliability Coordinators to only those identified in a Reliability Coordinator's Operating Plan. Otherwise, all other Reliability Coordinators would have to be notified which would be excessive. No change made. R7 – The SDT has decided to delete Requirement R7 in lieu of the more generic IRO-001-4, Requirement R1. See the summary consideration for the revision. R8 – Regarding your request to direct the notification in Requirement R8 to only those entities required to take action to prevent or mitigate an exceedance is well and good; however, it leaves out the entities which truly may only be impacted by the operating condition but do not have an active role to play in the mitigation plan. These entities deserve notification because the situation could mean that the impacted Load is at risk. Likewise they deserve notification when the situation has been cleared. No change made.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, FMPA believes R1 should refer to the performance requirements of FAC-011 R2 or specify "in accordance with its SOL Methodology" so that the breadth of contingencies to be studied is known.
Response: See SDT's response to FRCC's comments. The SDT believes the requirement as written is clear. Furthermore, the SDT believes that not exceeding any of "its" limits would require the entity to have its ratings set by their SOL methodology in conformance with current NERC standards. No change made.		
Duke Energy	No	R1: No Comment R2: Duke Energy believes that this requirement, as written, would be an administrative burden on the RC to review all Operating Plans of a TOP and BA within their RC area. We suggest removing R2 or combining R2 and R3 because coordination of SOL(s) and IROL(s) and their mitigation plans would not exist without the RC reviewing the plans of the TOP and BA. In addition, we believe duplicative evidence would be provided for both R2 and R3 which is why we suggest combining the two requirements or removing R2 entirely. R3: See comment for R2

Organization	Yes or No	Question 3 Comment
		R4: Per the Functional Model, the RC would only notify impacted TOPs and BAs as to their role in the Operating Plan. Using NERC registered entities goes against the roles defined in the Functional Model and Duke Energy suggests rewording as follows: ”Each Reliability Coordinator shall notify impacted BA(s) and TOP(s) identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s).”In addition, the coordinated plans identified in R3 are only the coordinated plans provided by the TOP(s) and BA(s) in its RC area. R5: While Duke Energy agrees, in general, that a Reliability Assessment shall be performed at least once every 30 minutes, we have concerns with this zero tolerance requirement. We believe a provision that allows for a defense in depth strategy is needed to allow the RC to develop a plan, process, or procedure for those instance where various tool(s) used to conduct the Reliability Assessment are unavailable for longer than 30 minutes. This would align with NERC’s transition to the RAI Initiative. In addition, EOP-008-1 R1.5 allows a transition period of less than or equal to 2 hours for a RC to transition to its backup control center. If a RC is in its transition phase and it takes longer than 30 minutes to become fully implemented, would the RC violate R13 of this requirement? It could take longer than 30 minutes for an entity to arrive at the backup control center for various reasons. This is one of the reasons why a defense in depth strategy is needed in this requirement. R6: Requiring the RC to notify the TOP(s)/BA(s) on every exceedance of an SOL may be burdensome and will be operationally distracting to the current role of the RC which is having a wide area view of their RC area. R7: See comment for R6. The requirement, as written, presumes the TOP/BA will fail to act. We believe the RC should take actions only when either the TOP/BA failed to act or if the RC disagreed with the mitigating plans of the BA/TOP. As such, we suggest the following language revision: ”Each Reliability Coordinator shall validate that the actions in the TOP(s)/BA(s) Operating Plan are appropriate and issue Operating Instructions, as necessary if: o The TOP/BA fails to implement the Operating Plan o The RC determines that the TOP/BA Operating Plan is insufficient”

Organization	Yes or No	Question 3 Comment
		Duke Energy believes this language better aligns with the proposed TOP-001-3 R13 that already requires the TOP to notify and share their Operating Plan used to mitigate SOL(s) with the RC. The RC should only be responsible for validating the TOP(s) Operating Plan and taking action if, and only if, the TOP fails to act or the RC deems the actions taken by the TOP are insufficient. R8: See comment(s) for R6 and R7.

Response: R1 – Thank you for your support.

R2 - Based upon your and other comments the SDT proposes to delete Requirement R2 as it is duplicative with Requirement R3 which requires the Reliability Coordinator's Operating Plan to be coordinated with the Operating Plans provided by its Balancing Authorities and Transmission Operators. That plan cannot be coordinated without reviewing the plans of the Balancing Authorities and Transmission Operators within the Reliability Coordinator's Area. See the summary consideration for the revision.

R3 – See the response to Requirement R2 above.

R4 – The SDT agrees with your comment; however, there may be situations where entities other than Balancing Authorities and Transmission Operators may be identified to take an active role in an Operating Plan. However, the SDT has deleted 'NERC registered' due to comments received. See the summary consideration for the revision.

R5 –The SDT has revised the wording of Requirement R5 based on your comments and those of others. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's loss of control center functionality Operating Plan. The SDT believes that the TOP-001-3, IRO-008-2 and EOP-008-1 Requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, EOP-008-1 Requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Organization	Yes or No	Question 3 Comment

The 30-minute requirement and the definition of "Real Time assessment" does not specify the manner in which an assessment is performed nor does it preclude RCs and TOPs from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the TOP could rely on the RC to perform a Real-time Assessment or even review their RC's contingency analysis results when their tools are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform an RTA and determined that the modified language is sufficient to coordinate with the existing requirements of standard EOP-008 and should not introduce any requirement timing conflicts.

R6 – Reliability Coordinators are already required to notify Balancing Authorities, Generator Operators, and Transmission Operators when there is an actual or expected condition whereby an SOL or IROL is exceeded. Please reference approved IRO-005-3.1a Requirement R6 and approved IRO-009-1 Requirement R4. Requirement R6 does not require any more from the Reliability Coordinator than is currently being requested. No change made.

R7 – The SDT has decided to delete Requirement R7 in lieu of the more generic IRO-001-4, Requirement R1. See the summary consideration for the revision.

While deleting Requirement R7 eliminates the need for making language changes as proposed in your comment, the fact remains that the Reliability Coordinator, Transmission Operator and Balancing Authority all have the authority to issue Operating Instructions. Overlap does exist between the Reliability Coordinator and Transmission Operator roles as well as between the roles of the Reliability Coordinator and the Balancing Authority. However, the clarification for that functionality is found in the Functional Model not in the reliability standards. The IRO standards are Reliability Coordinator based. Transmission Operator actions are covered in TOP standards. Likewise, the BAL standards, as well as some TOP standards, cover the requirements for Balancing Authorities. While the roles of the Reliability Coordinator and Transmission Operator are very similar, the scopes are considerably different. The Transmission Operator is responsible for reliably operating within its Transmission Operator Area whereas the Reliability Coordinator is responsible for a wide-area view which may encompass several Transmission Operator Areas. Both functions have the authority to direct other functional entities within its respective area to ensure reliable operations. A similar situation exists between the Reliability Coordinator and the Balancing Authority. It takes a shared, coordinated effort among all three entities to maintain reliability. No change needed with the deletion of the requirement.

R8 – See the SDT response to your comments on Requirements R6 and R7 above.

Organization	Yes or No	Question 3 Comment
Bureau of Reclamation	No	Reclamation suggests that R4 should list the applicable "impacted NERC registered entities" that must be notified when they have roles described in Operating Plans (e.g., Generator Operators, Distribution Providers, etc.).
Response: Based on your and other comments on the use of 'NERC registered entities', the SDT proposes to delete 'NERC registered' and modify the requirement to reflect the relationships among the Reliability Coordinator and its Balancing Authorities and Transmission Operators. See the summary consideration for the revision.		
SPP Standards Review Group INDN - Independence Power & Light	No	Hyphenate 'next-day' in Requirement R1. We suggest slightly rewording Requirement R3 to read: 'Each Reliability Coordinator shall have a coordinated Operating Plan(s) for the next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities in Requirement R2.' Requirement R5 requires a Real-time Assessment be performed at least once every 30 minutes. This is technically infeasible in some situations where there is missing data and/or the state estimator does not solve properly. An assessment cannot be completed under these conditions. Being a zero tolerance standard, this sets the industry up to fail. One of the largest categories of events being reported under event analysis is EMS or state estimator outages. Additionally, even if the state estimator does solve, can we be assured that the solution is correct in these situations? Also, just because the state estimator has solved doesn't necessarily mean that each contingency in RTCA is a valid solution. The language needs to be modified to reflect this situation. Perhaps the requirement should be focused on a normal schedule for a Real-time Assessment every 30 minutes but consideration would be given for situations where the tools that are currently available to the industry simply cannot provide the desired outcome. If the standard maintains the 30 minute or some similar time frame requirement, logging the completion of those assessments and

Organization	Yes or No	Question 3 Comment
		maintaining records will prove to be burdensome to the industry requiring additional personnel simply to staff this capability. This argument applies to the Transmission Operator in TOP-001-3, Requirement R13. Replace 'Real-Time' with 'Real-time' in Measure M5.

Response: Your suggested change to Requirement R1 has been made. See the summary consideration for the revision.

Your suggested change to Requirement R3 has been made. See the summary consideration for the revision.

The SDT has altered Requirement R5 to address your concern and those of others. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's loss of control center functionality Operating Plan. The SDT believes that the TOP-001-3, IRO-008-2 and EOP-008-1 Requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, EOP-008-1 Requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The 30-minute requirement and the definition of "Real Time assessment" does not specify the manner in which an assessment is performed nor does it preclude RCs and TOPs from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the TOP could rely on the RC to perform a Real-time Assessment or even review their RC's contingency analysis results when their tools are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform an RTA and determined that the modified language is sufficient to coordinate with the existing requirements of standard EOP-008 and should not introduce any requirement timing conflicts. See the summary consideration for the revision.

Your suggested change to Measure M5 has been made. See the summary consideration for the revision.

Organization	Yes or No	Question 3 Comment
ACES Standards Collaborators	No	(1) For Requirement R1, there is an incorrect glossary term listed. The term should be “Reliability Coordinator Area” not “Reliability Coordinator Wide Area.” There is no listing of any new proposed terms, so this needs to be aligned with the correct term in the NERC glossary. (2) Requirement R3 is wordy and leads to confusion. There is no need to cross reference R1 and R2, as this is a natural succession of requirements. This requirement should be combined with R1. (3) Requirement R4 should be combined with R1. (4) Requirement R5 should be combined with R1. (5) The drafting team should reevaluate this standard and consider options to consolidate and combine requirements. There are several areas stated above that could be grouped together into a single requirement or fewer requirements that would still meet the purpose of the standard.
Response: (1) The SDT has deleted Reliability Coordinator from the Reliability Coordinator Wide Area term. See the summary consideration for the revision. (2) Based upon your and other comments the SDT proposes to delete Requirement R2 as it is duplicative with Requirement R3 which requires the Reliability Coordinator’s Operating Plan to be coordinated with the Operating Plans provided by its Balancing Authorities and Transmission Operators. That plan cannot be coordinated without reviewing the plans of the Balancing Authorities and Transmission Operators within the Reliability Coordinator’s Area. See the summary consideration for the revision. With the deletion of Requirement R2, there is a need to keep the reference to consideration of Operating Plans provided by Balancing Authorities and Transmission Operators. (3), (4), & (5) Combining multiple, distinct activities into a single requirement creates issues when developing VSLs. The VSLs become multi-layered, increasing their complexity. No change made.		
ISO/RTO Standards Review Committee (SRC)	No	We agree with all the proposed changes except we find a discrepancy between the rationale for Requirements R6 and R7, and between Requirement R6 and its VSL with respect to the use of the word “Emergency”. The Rationale box suggests that the

Organization	Yes or No	Question 3 Comment
		language in R6 has been changed from IROL exceedance to Emergency, as Emergency is a stronger term which includes IROL exceedance and thus raises the bar for this requirement. Requirement R7 is the extension of Requirement R6 ensuring actions are taken to deal with the Emergency. However, we see that both R6 and R7 continue to make reference to SOL or IROL exceedance, and the word “Emergency” is not used. In fact, we support keeping the SOL or IROL language in the two requirements since either can occur before an entity declares or enters into an Emergency, but the anticipated or actual SOL/IROL exceedance must be addressed as soon as possible without delays as supported by R6 and R7. Hence, we suggest the SDT to keep the language in R6 and R7, and revise the Rationale box accordingly. Also, the LOWER VSL for R6 makes reference to “Emergency”, which should be corrected. Comment on R1: Replace ‘or’ with ‘and’. Comment on R5: We ask that the drafting team confirm that Real-time Assessments are not limited to software applications, specifically a contingency analysis tool. R2 - The concept of an RC review of each TOP and each BA’s OPA seems questionable from a practical perspective. M2 requires proof of such an action. While RCs may indeed screen some of the more important OPAs, why must the RCs look at them all? And worse, why must that proof be retained?
Response: The Rationale Box for Requirement R6 has been changed for consistency. See the summary consideration for the revision. The term ‘Emergency’ does not appear in the VSLs for Requirement R6. No change made. Your suggested change to Requirement R1 has been made. See the summary consideration for the revision. There is nothing in the definition of Real-time Assessment that limits the platform for conducting the evaluation of Real-time system conditions to a Contingency analysis tool, i.e. an RTCA tool. Based upon your and other comments the SDT proposes to delete Requirement R2 as it is duplicative with Requirement R3 which requires the Reliability Coordinator’s Operating Plan to be coordinated with the Operating Plans provided by its Balancing Authorities		

Organization	Yes or No	Question 3 Comment
and Transmission Operators. That plan cannot be coordinated without reviewing the plans of the Balancing Authorities and Transmission Operators within the Reliability Coordinator's Area. See the summary consideration for the revision.		
Georgia System Operations Georgia Transmission Corporation	No	By the various uses of "Operating Plan" in Requirements 1 through 8, does the SDT consider this to be a single continuously updated operating plan or does the SDT expect an Operating Plan to be developed for next day assumptions which then transitions into a different operating plan when a real time condition is observed? GSOC agrees with its RC that IRO-008-2 Requirement 2 will pose an administrative burden on the Reliability Coordinator as it is currently worded. It will require RCs to produce an email response to all TOP and BA operating plans stating "reviewed". RCs are required to have a coordinated Operating Plan considering the Operating Plans provided by its TOPs and BAs in the proposed R3. In order for the RC to develop an Operating Plan, as required by R3, the RC must review its TOPs and BAs plans; therefore, making R2 unnecessary.
Response: R1-R8 – An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances		

Organization	Yes or No	Question 3 Comment
identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes. No change made. Based upon your and other comments the SDT proposes to delete Requirement R2 as it is duplicative with Requirement R3 which requires the Reliability Coordinator's Operating Plan to be coordinated with the Operating Plans provided by its Balancing Authorities and Transmission Operators. That plan cannot be coordinated without reviewing the plans of the Balancing Authorities and Transmission Operators within the Reliability Coordinator's Area.		
ReliabilityFirst	No	ReliabilityFirst submits the following comments for consideration: 1. Requirement R7 - The phrase "as necessary" is ambiguous and leaves the requirement open to interpretation and therefore, difficult to enforce. RF suggests removing the phrase "as necessary", which is vague and creates concerns similar to those expressed by the Commission in Order 791. In Order 791, the Commission supported the RAI's goal to develop a framework for the ERO Enterprise's use of discretion in the compliance monitoring and enforcement space, but rejected the codification of "identify, assess, and correct" language within the CIP Version 5 Reliability Standards because it is vague. ReliabilityFirst is also concerned that the qualifier "as necessary" codifies discretion within IRO-008-2. ReliabilityFirst believes that neither discretion nor controls should be codified in Reliability Standards. Rather, the ERO Enterprise should utilize discretion in the compliance monitoring and enforcement space when determining the relevant scope of audits and whether to decline to pursue a noncompliance as a violation. With the RAI, the ERO Enterprise is developing a singular and uniform framework to inform the ERO Enterprise's use of discretion in the compliance monitoring and enforcement space. Therefore, ReliabilityFirst recommends removing the qualifier "as necessary" from R7 and allow the ongoing RAI effort to create a

Organization	Yes or No	Question 3 Comment
		meaningful and unambiguous framework that the ERO Enterprise will utilize to inform its use of discretion in the compliance monitoring and enforcement of all Reliability Standards. ReliabilityFirst cautions that codifying discretion in some Reliability Standards may create confusion once the ERO Enterprise begins to implement the RAI and its discretion in compliance monitoring and enforcement work. For example, there may be confusion of whether discretion codified in certain Requirements of Reliability Standards precludes the ERO Enterprise's use of RAI discretion for those Requirements where discretion is not codified. ReliabilityFirst offers the following for consideration: "Each Reliability Coordinator shall issue Operating Instructions, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6."
Response: The SDT has decided to delete Requirement R7 in lieu of the more generic IRO-001-4, Requirement R1. See the summary consideration for the revision.		
American Transmission Company	No	R1 - Although proposed IRO-008-2 is not applicable to ATC, ATC suggests the removal of the word "Wide" from the term "Reliability Coordinator Wide Area" in Requirement R1. "Reliability Coordinator Wide Area" is not currently defined, nor proposed for inclusion in NERC's Glossary of Terms.
Response: The SDT has deleted Reliability Coordinator from the Reliability Coordinator Wide Area term. See the summary consideration for the revision.		
David Kiguel	No	R4: Notification requirement should be extended to all impacted entities, regardless of NERC registration. In some jurisdictions, e.g. Province of Ontario, NERC registration is not required for entities other than the IESO. Same may be possibly valid for other Canadian Provinces.

Organization	Yes or No	Question 3 Comment
Response: Thank you for reminding us of operating differences across our northern border. Based on your and other comments on the use of 'NERC registered' the SDT decided to modify the language in Requirement R4 to 'notify impacted Balancing Authorities, Transmission Operators and other entities identified in the Operating Plan(s)'. See the summary consideration for the revision.		
PJM Interconnection	No	Please see PJM's comments included in Question #12.
Response: Please see response to comments in Question 12.		
Consumers Energy	No	R6, R7, R8 - The Rationale says that "IROL exceedance" was replaced with "emergency", but "emergency" does not appear in the Requirement; "IROL exceedance" does. It doesn't appear that SDT did what they claim.
Arizona Public Service Company	Yes	IRO-008 R6: The Rationale box says that the "language changed from IROL exceedance to Emergency..." But the language in the draft standard actually uses IROL exceedance and not Emergency
Response: The 'Emergency' references in the Rationale Box for Requirement R6 have been deleted for consistency. See the summary consideration for the revision.		
Independent Electricity System Operator	No	We agree with all the proposed changes except we find a discrepancy between the rationale for Requirements R6 and R7, and between Requirement R6 and its VSL with respect to the use of the word "Emergency". The Rationale box suggests that the language in R6 has been changed from IROL exceedance to Emergency, as Emergency is a stronger term which includes IROL exceedance and thus raises the bar for this requirement. Requirement R7 is the extension of Requirement R6 ensuring actions are taken to deal with the Emergency. However, we see that both R6 and R7 continue to make reference to SOL or IROL exceedance, and the word "Emergency" is not used. In fact, we support keeping the SOL or IROL language in the two requirements since either can occur before an entity declares or enters into an Emergency, but the anticipated or actual SOL/IROL exceedance must be addresses as soon as possible

Organization	Yes or No	Question 3 Comment
		without delays as supported by R6 and R7. Hence, we suggest the SDT to keep the language in R6 and R7, and revise the Rationale box accordingly. Also, the LOWER VSL for R6 makes reference to “Emergency”, which should be corrected.
Response: The ‘Emergency’ references in the Rationale Box for Requirement R6 have been deleted for consistency. See the summary consideration for the revision. The term ‘Emergency’ does not appear in the VSL for Requirement R6. No change made.		
Electric Reliability Council of Texas, Inc.	No	The reference in R6 and R8 to “as indicated in its Operating Plan” is unnecessary and only creates additional compliance burden. Operating conditions can change very quickly that can cause a “plan” to vary and the impacted entities to vary. That phrase should be deleted. In R7, “to deal with” should be replaced with “to prevent or mitigate”. In R2-R3, the current definition of Operating Plan states “a document”. While this context is appropriate for processes/procedures determined well in advance of real time. The timeframe described is really next day and while most “Operating Plans” are documented, all plans to operate reliably may not be documented or in “a document”. The definition should be modified to address this new usage of the term to make it appropriate for all its uses, or a different term should be used. In its current form, it may lead to unnecessary administrative violations due to the lack of having “a document” rather than operations being coordinated and have a plan to operate reliably. The plan can be still coordinated but exist in various systems and conversations/emails/documents. This presents similar challenges for R4 as well as it further infers a single “document” and have several required elements. This can be overly prescriptive and burdensome. R4 further should not be limited to verbal or written notification if it remains. Some “plans” could be to commit additional generation. In the day-ahead process, the “notification” could occur via systems or other equivalent means. The connotation of

Organization	Yes or No	Question 3 Comment
		a “document” and “notification” identifying “roles” creates a layer of inefficiencies and manual administrative actions that are unnecessary if the planning and notification occurs via other means. R5 does not have any context surrounding it if an entity loses real time tools it utilizes to conduct a Real Time Assessment. It should not be a violation if an entity has analysis tool outages that cause a reasonable time deviation from a normal 30 minute timeframe. For example, if real time tools are not available some effort is given by System Operators in troubleshooting and corrective actions to make the real time tools available again. For example, by allowing 45-60 minutes as an alternative means, like conducting offline studies, is more reasonable to allow time for initial troubleshooting, then a decision to run the offline study, then to actually conduct the offline study without a violation for an abnormal situation that is still handled in a reliable fashion. While the current requirement has 30 minute requirement, IROLs are typically determined ahead of time or are so specific that the N-1 limit may still be valid if system topology has not changed thus allowing for continual Real Time Assessment even if the tool is unavailable temporarily. The introduction of SOL for the 30 minute Real Time Assessment introduces a new challenge relative to that of Real Time Contingency Analysis for thermal and voltage exceedances and all of the Facilities it takes into account vs the limited ones for IROLs. Currently proposed R8 is problematic for the ERCOT RC as potential SOL exceedances may show up as post contingency thermal facility rating exceedances that are then managed by the ERCOT Nodal market operations system as detailed in IRO-006-TRE. To notify a Transmission Operator that may or may not have to take a manual action depending on if the ERCOT Nodal market operations system resolves the SOL exceedance, would be unduly burdensome and result in a high volume of unnecessary communications. It should be explored as an alternative way to clarify somehow that it would be limited to actual “basecase” facility rating exceedances, not post contingency for thermal limits or for N-1 stability/IROL type exceedances. Alternatively, allow for the RC to identify when it would be appropriate to notify the

Organization	Yes or No	Question 3 Comment
		impacted entities and when not to in its Operating Processes and Operating Procedures to notify an entity. As it stands today, it is not feasible.

Response: R6-R8 – Regarding your suggested wording for Requirements R6 and R8, the phrase 'as indicated in its Operating Plan' limits the notification of other Reliability Coordinators to only those identified in a Reliability Coordinator's Operating Plan. Otherwise, all other Reliability Coordinators would have to be notified which would be excessive. No change made.

R7 – The SDT has decided to delete Requirement R7 in lieu of the more generic IRO-001-4, Requirement R1. See the summary consideration for the revision.

R2 & R3 – An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative

Organization	Yes or No	Question 3 Comment
burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes. No change made. There is nothing in Requirement R4 which restricts the notification of a role in an Operating Plan to verbal or written communications exclusively. As indicated in the preceding comment, an Operating Plan contains a generic treatment of all the processes, procedures, and hardware and software systems that are at the operator's disposal. Those items could include specific provisions for notification of impacted entities. No change made. R5 – The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30 minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's loss of control center functionality Operating Plan. The SDT believes that the TOP-001-3, IRO-008-2 and EOP-008-1 Requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, EOP-008-1 Requirements address: • **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. • **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The 30- minute requirement and the definition of "Real-time Assessment" does not specify the manner in which an assessment is performed nor does it preclude RCs and TOPs from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the TOP could rely on the RC to perform a Real-time Assessment or even review their RC's contingency analysis results when their tools are unavailable and vice-versa. The SDT did modify the requirement language to changes "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform an RTA and determined that the modified language is		

Organization	Yes or No	Question 3 Comment
sufficient to coordinate with the existing requirements of standard EOP-008 and should not introduce any requirement timing conflicts. See summary consideration for revision. R8 – As mentioned in the response to your concerns regarding Operating Plans in Requirements R2 and R3 and your concern regarding notification in Requirement R4, specific concerns addressing unique situations within the ERCOT market could be treated accordingly in the Operating Plan. No change made.		
Texas Reliability Entity	No	1) R3: Recommend replacing "to address potential System Operating Limit..." with "to address any anticipated (pre-Contingency) and potential (post-Contingency) System Operating Limit...". This change would be consistent with the terminology used in the proposed definition of Operational Planning Analysis. 2)R4: From the compliance and enforcement perspective it is important to know if the RC is required to notify impacted entities on a daily basis for Operating Plans that have extended impact (e.g. An Operating Plan based on an outage lasting a week) or just at the beginning? What is the intent of the SDT?
Response: R3 – The SDT feels that pre-Contingency and post-Contingency are contained in the definitions of SOL and IROL and adding that language would create redundancy with the current language of monitoring SOL and IROL exceedances. Please refer to the SDT's whitepaper on SOL Definition and Exceedance Clarification for additional information regarding the SDT's intent with regard to the SOL concept. R4 – Daily notifications would not be required for conditions which create an extended impact situation. The Reliability Coordinator would have notified the responsible entities of the condition upon identification. The responsible entity would be correct in assuming that the condition continues to exist until it is notified in Requirement R8 that the condition has been prevented or mitigated.		
MidAmerican Energy	No	Specific to IRO-008-2, R5, MidAmerican is concerned with the compliance overlap and potential non-compliance with EOP-008, R5 which provides for a two hour timeframe to have the back-up facility fully functional. MidAmerican recommends the addition of language in IRO-008-2, R5 to provide relief to the RC for the period

Organization	Yes or No	Question 3 Comment
		when evacuation to the back-up facility is necessary and the timeframe it takes for the back-up control center to be fully functioning. Additionally, the VRF and VSLs for R5 will require revision to address the two hour timeframe allowed for in EOP-008.
Response: The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's loss of control center functionality Operating Plan. The SDT believes that the TOP-001-3, IRO-008-2 and EOP-008-1 Requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, EOP-008-1 Requirements address: • **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. • **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The 30- minute requirement and the definition of "Real-time Assessment" does not specify the manner in which an assessment is performed nor does it preclude RCs and TOPs from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the TOP could rely on the RC to perform a Real-time Assessment or even review their RC's contingency analysis results when their tools are unavailable and vice-versa. The SDT did modify the requirement language to changes "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform an RTA and determined that the modified language is sufficient to coordinate with the existing requirements of standard EOP-008 and should not introduce any requirement timing conflicts. In addition, the VSLs have been changed to reflect such concerns. See summary consideration for revisions.		
Peak Reliability	Yes	o R1 - "...planned operations for the next day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Wide Area" should be "planned operations in its Wide Area for the next

Organization	Yes or No	Question 3 Comment
		day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Area” o R5: Language should be added to this Requirement to allow for tool outages. Adding “when tools are operating as expected” is an option. o R7: this Requirement is duplicative of IRO-001-4 R1. Although R7 is more specific than IRO-001-4 R1, R7 is covered by IRO-001-4 R1.

Response: R1 – The SDT has deleted Reliability Coordinator from the Reliability Coordinator Wide Area term. See the summary consideration for the revision.

R5 – The SDT has altered the requirement to address your concern and those of others. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity’s loss of control center functionality Operating Plan. The SDT believes that the TOP-001-3, IRO-008-2 and EOP-008-1 Requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, EOP-008-1 Requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The 30- minute requirement and the definition of “Real-time Assessment” does not specify the manner in which an assessment is performed nor does it preclude RCs and TOPs from taking “alternative actions” and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the TOP could rely on the RC to perform a Real-time Assessment or even review their RC’s contingency analysis results when their tools are unavailable and vice-versa. The SDT did modify the requirement language to changes “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform an RTA and determined that the modified language is sufficient to coordinate with the existing requirements of standard EOP-008 and should not introduce any requirement timing conflicts. In addition, the VSLs have been changed to reflect such concerns. See summary consideration for revisions.

Organization	Yes or No	Question 3 Comment
R7 – The SDT has decided to delete Requirement R7 in lieu of the more generic IRO-001-4, Requirement R1. See the summary consideration for the revision.		
Salt River Project	Yes	This standard significantly increases the communications required from the RC on the results of data exchanges, Operational Planning Analysis results, etc. This increase in communication could cause confusion about what is a potential problem being communicated per the requirements or and what is a true real-time problem.
Response: Reliability Coordinators should already be notifying entities whenever 1) they have a specific role to play in any anticipated operating situation, 2) they are impacted by planned operations within its Reliability Coordinator Area, 3) there is an actual or expected condition whereby an SOL or IROL is exceeded, and 4) whenever those conditions creating the impact have been prevented or mitigated. With the proposed deletion of Requirement R2 due to other comments, Reliability Coordinators are not being required to provide any more notification/confirmation than currently required. No change made.		
PacifiCorp	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Bonneville Power Administration	Yes	
Rayburn Country Electric Cooperative	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	

Organization	Yes or No	Question 3 Comment
EDP Renewables North America LLC	Yes	
Exelon Ccompanies	Yes	
Xcel Energy	Yes	
PNMR	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Hydro One	Yes	
NV Energy	Yes	
Response: Thank you for your response.		

4. Do you agree with the changes made to proposed IRO-010-2? If not, please provide technical rationale for your disagreement along with suggested language changes.

Summary Consideration: The SDT changed the Implementation Plan for Requirements R1 and R2 from 10 months to 9 months. Most of the other comments received were about clarifications of the proposed language. The SDT has provided requested clarifications and in addition has made the following change based on industry comments – Planning Coordinator and Transmission Planner have been deleted from Requirement R3 as those entities do not fit in the data specification concept. While data is transferred between a Reliability Coordinator, Planning Coordinator, and Transmission Planner, it is done in a less structured, more informal, ad hoc basis as the data is needed as opposed to a regular, structured data transfer as set up by a data specification.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	Similar to TOP-003, R1 and R2 VRFs should be Low, not Medium.
Response: Please see response to question 14.		
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	R1.1 - Does this mean a generic type of data required or a detailed list of data points? R3 - Why is LSE included with the planned retirement of LSEs? Why is TP and PC included in this requirement? The TP and PC horizon timeline does not fit within the Operations Planning horizon.
Response: Requirement R1, Part1.1 requires a detailed list of data points. R3 – There are active discussions about the future role of the Load-Serving Entity but for the moment it is included in the Functional Model v5. The SDT is required to follow that document in its work. If the group looking into the deletion of Load-Serving Entity decides to eliminate it, it will be the responsibility of that group to come up with a plan to bring the body of standards up to date.		

Organization	Yes or No	Question 4 Comment
Planning Coordinator and Transmission Planner have been deleted from Requirement R3 as those entities do not fit in the data specification concept. While data is transferred between a Reliability Coordinator, Planning Coordinator, and Transmission Planner, it is done in a less structured, more informal, ad hoc basis as the data is needed as opposed to a regular, structured data transfer as set up by a data specification.		
Dominion	No	Dominion does not agree with the purpose statement as written. It infers that ensuring the RC has data necessary to monitor and assess the operation of its Reliability Coordinator Area will somehow prevent instability, uncontrolled separation, or Cascading outages. Dominion suggests revising similar to “To ensure the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.” Dominion does not agree with R1.1 as written. We are opposed to the inclusion of the phrase “including sub-100 kV facilities”. It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. Dominion does not see a distinct difference between sub-requirements 1.3 and 1.4. We believe that periodicity infers the deadline.
Response: The SDT believes that the Purpose Statement accurately reflects the goal of this standard. No change made. Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made. Requirement R1, Part 1.3 refers to the periodicity of the data, i.e., how often the data must be supplied. Requirement R1, Part 1.4 refers to the deadline for the initial provision of the data point, i.e., when you need to respond to a new request for data. No change made.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services).

Organization	Yes or No	Question 4 Comment
		In addition, R1 should specify a "minimum" set of data requirements. This is especially apparent when protection system status is called out in 1.2, but the status of the Facilities being protected is not called out - which is more important to reliability? Due to the ambiguity of what is and is not included in R1, other SDTs for other standards were unwilling to accept that there is duplication (see comments to TOP-003 R1 and R2 for more detail). The only way to eliminate the duplication, redundancy and confusion in the standards will be to develop a minimum list of data in R1 so that it is clear that the data is included. FMPA believes that lack of specificity, while presumably simplifying the standards, actually makes them more complicated because we are unable to resolve overlap between standards. As such, we propose the SDT develop a "minimum" set of data, notification, information, etc., requirements as an attachment to the standard. RCs can always specify more if so desired.
Response: See response to FRCC comments. The SDT believes that the requesting entity, in this case the Reliability Coordinator, is in the best position to know what it needs to preserve reliability. One size does not fit all here as each system is different. The requirement is written to respect that fact and to allow individual Reliability Coordinator's to craft the list as they see fit using its professional judgment. The Transmission Operator and Balancing Authority would always be able to suggest additional data points if the Reliability Coordinator did not request them initially. No change made.		
Duke Energy	No	R1: The proposed definition for Operational Planning Analysis clearly relates to condition for next-day operations. However, the time horizon identified in this requirement (next day to 1 year out) is beyond the scope of the definition. The proposed definition does not make reference to time horizons post next-day operations. In addition, the scope of R1 goes above and beyond the prevue of the RC as currently defined in the NERC Functional Model. . Duke Energy suggests removing Operations Planning and adding Real-Time Operations and Same-Day Operations. R2: Duke Energy suggest rewording R2 as follows: "The Reliability Coordinator shall distribute its data specification to Applicable entities that have data required by the

Organization	Yes or No	Question 4 Comment
		Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." The addition of "Applicable entities" will limit the data specification to only those entities that need to provide data to the RC. In addition, we have the same comment on Time Horizon as is stated in R1.R3: Suggest removing Operations Planning Horizon for the reasons mentioned above.
Response: The data specification is set up in advance in order for the Reliability Coordinator to receive the data it needs when it needs it. Therefore, the Time Horizon is not a Real-time or same-day issue but a 'planning' issue and is accurately recorded as Operations Planning. No change made. The SDT does not believe that the suggested change adds clarity. No change made. The Time Horizon for Requirement R3 is written to acknowledge the fact that there will probably be different data streams for operations planning and Real-time or same-day operations. No change made.		
BC Hydro and Power Authority	No	The new Requirement has the Reliability Coordinator able to ask for "sub-100 kV' data if it deems necessary. This is an increase in scope from the data the RC currently asks for. As this data may be outside the BES definition, BC Hydro does not support this increase in scope.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made.		
SPP Standards Review Group	No	The Rationale Box under the Applicability Section explains why the Interchange Authority was absolved of responsibility for IRO-010-2. That same justification should be used to remove the Interchange Authority from the Applicability Section of TOP-003-3.

Organization	Yes or No	Question 4 Comment
		There is some confusion as to just what needs to be included in the data specification required in Requirement R1. In order to minimize confusion we recommend that the drafting team include clarification in the Application Guidelines which, for example, states that the specification does not have to be a point-by-point listing of all data points to be exchanged. Capitalize 'Part' in the Rationale Box for Requirement R1.
Response: The SDT agrees and has removed Interchange Authority from proposed TOP-003-3. Ultimately, a point-by-point listing will be necessary, although the process may begin with a higher-level specification, such as "all line statuses, MW/MVAR flows and bus voltages for all transmission assets controlled by this Transmission Operator." It is doubtful that a Reliability Coordinator would necessarily know all of the points in detail for a Transmission Operator new to its Reliability Coordinator Area, but likely that it would know the listing of points for existing, mature Transmission Operators. No change made. The SDT agrees and has capitalized "Part" as suggested.		
ACES Standards Collaborators	No	(1) We disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity. Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly impact reliability, are redundant, and handle data requests and submittals. Further, asking for non-BES data is out of scope of the jurisdictional bounds of reliability standards. (2) Requirement R2 should be combined with R1. A simple insertion of "maintain and distribute" in R1 would result in the same outcome with fewer requirements to comply with. (3) Requirement R3's language of "mutually agreeable" is challenging for compliance because it requires additional documentation to show that the data was submitted in a "mutually acceptable format." The requirement should be that entities must

Organization	Yes or No	Question 4 Comment
		submit the applicable data by the required timeline. The SDT has made a straight-forward process very complicated for compliance purposes.
Response: (1) Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made. (2) The SDT believes that the distribution of the specification is a sufficiently different action from the creation of the specification that a separate requirement is justified. No change made. (3) "Mutually agreeable" allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can't force a solution on the other entity when that entity may not be physically capable of performing**.** No changes made.		
ISO/RTO Standards Review Committee (SRC) Independent Electricity System Operator	No	We agree with the proposed changes, but are unable to locate R1, Part 1.7 as indicated in the Rationale box above R1, that: "Proposed Requirement R1, part 1.7 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks." We are therefore uncertain as to how the concerns raised in Paragraph 92 (and in the next several paragraphs) of the FERC NOPR are addressed.
Consumers Energy	No	R1 - The Rationale refers to a R1, part 1.7, but no such part exists in the posted draft.
Colorado Springs Utilities	Yes	1. Proposed Requirement R1, part 1.7 rationale does not reference the standards correctly and does not appear to belong to R1.
Response: The rationale box has been corrected to read "Proposed Requirement R3, Part 3.3 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks." This directly addresses Paragraph 92 of the NOPR.		
Rayburn Country Electric Cooperative	No	Similar to my comments on IRO-001 and TOP-001 I think this could be combined with TOP-003-3 in a similar manner. GROUP 1Any of the following: Reliability Coordinator

Organization	Yes or No	Question 4 Comment
		Balancing Authority Transmission Operator GROUP 2Any of the following: Transmission Operator Balancing Authority Generator Owner Generator Operator Interchange Authority Load-Serving Entity Transmission Owner Distribution Provider R1. GROUP 1 shall maintain a documented specification for the data necessary for it to perform its analysis, monitoring and assessments as required. The data specification shall include, but not be limited to: (Maintain the use of general specifications only, detailed specificity can be within each functional entities published data specification) R2. GROUP 1 shall distribute its data specification to entities that have data required by GROUP 1 to perform its analysis, monitoring and assessments. R3. A GROUP 2 member receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: 3.1. A mutually agreeable format 3.2. A mutually agreeable process for resolving data conflicts 3.3. A mutually agreeable security protocol Any specificity related to data required by each respective function should be identified within their data specification not within the reliability standard. For example, if the RC needs sub 100kV information, that can be identified with justification within the data specification.
Response: The SDT purposely kept proposed IRO-010-2 and proposed TOP-003-3 separate to keep the focus on the functional entities responsible: Reliability Coordinators for proposed IRO-010-2 and Transmission Operators and Balancing Authorities for proposed TOP-003-3. This was part of the scope for the originating projects (Project 2006-06 and Project 2007-03). No change made.		
Volkmann Consulting	No	IRO-010 should have a 4th requirement that requires the RC to determine and communicate any deficiency of data received back to the applicable entity providing the data. R3 requires the sending of data to the RC, but does not require the determination of adequacy. For larger systems, it is impossible to prove every piece of data is being sent per the specification. In all cases the RC know if they have enough data, but performance of its real-time processes and tools. The RC should be required to communicate data deficiencies and not rely on the Audit process.

Organization	Yes or No	Question 4 Comment
Response: The SDT believes that the requirements are written such that the onus for performance is on the Reliability Coordinator. Therefore, the Reliability Coordinator will have every reason to be continually checking the data for accuracy or any deficiencies and that this becomes a technicality that does not rise to the level of a mandatory standard. No change made.		
City of Garland	No	Requirement # 1Concern is with the portion of the definition of "Operational Planning Analysis" and "Real Time Assessments" that lists "identified phase angle". It is not clear what "identified" means. "Identified" should mean that the RC will identify representative points across the area for which the RC is responsible - not every available point in the system (larger geographic areas would probably need more points than small geographic areas). Also, PMUs require a large bandwidth to pass the tremendous amount of data collected thus making the communication costs prohibitive for small entities.
Response: The part of the definition that is referenced here is actually "… and identified phase angle and equipment limitations…" This means that any identified limitations in dealing with phase angles should be incorporated into the analysis. No change made. If an entity does not have PMU data then this is not an issue. If an entity has PMU data, then the SDT believes that the entity will have built its systems to be able to handle the volume of data associated with the PMU data. The Reliability Coordinator is not going to request data just for the sake of having it and will only request data that it truly needs. This could assist in dealing with the volume of data going across the link. In addition, the requirement cites mutual agreeability which assures that the controlling entity can't request something that the submitting entity simply can't provide. No changes made.		
Ingleside Cogeneration LP	No	R1.1 allows the Reliability Coordinator to require downstream entities to provide certain sub-100 kV data and external network data needed to support operational reliability. Although ICLP agrees with the fundamental premise, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new Definition of the BES. This process was developed precisely for this reason - and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. Without this limitation, we can see that the standard will be applied unevenly across Reliability

Organization	Yes or No	Question 4 Comment
		Coordinators; which works against the fundamental intent of reliability standardization. Secondly, ICLP does not see the reasoning behind moving the responsibility for maintaining a mutually agreeable data format, data conflict resolution process, and security protocol to the data providers (R3). The RC should provide those specifications and processes under Requirement R1 as is the case in the existing standard. If there is an issue with the term “mutually agreeable”, the onus could be put on the data provider to demonstrate that an alternate format/process/protocol is needed in their specific instance.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made. “Mutually agreeable” allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can’t force a solution on the other entity when that entity may not be physically capable of performing**.** No changes made		
Idaho Power	No	I agree with the revisions to IRO-10-2 but have concerns with requirement 3. If the RC is willing to provide attestation that the requirement has been fulfilled it will be no problem. If the entity is required to provide evidence it will be more difficult. You could retain all the emails but how do you prove that was all the requests.
Response: The measure is written to allow for attestations to be provided as suitable evidence of compliance and the SDT believes that such attestations will be provided if requested. No change made.		
Liberty Electric Power, LLC	No	There are two types of data falling under the standard, and they should be treated differently in the requirements. Data requests are fine as written, but data transmitted automatically for real-time purposes should be handled with a separate requirement. The requirement should be for the data provider to provide the

Organization	Yes or No	Question 4 Comment
		specified data as required, but with a measure that shows the RTU or other data transmission device is installed and operational. There is no log of this data, and requiring an attestation is too burdensome for the RC, who may be required to provide hundreds of documents in response to the requirement.
Response: The requirements as written cover both unique data requests and regularly scheduled automatic data submittals. The Reliability Coordinator will be regularly and continually checking the data it receives and thus providing an attestation, if requested, should not be a burden. No change made.		
Electric Reliability Council of Texas, Inc.	No	Thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems, will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.
Response: Protection Systems were added due to concerns raised in NOPR paragraph 78. The intent of such changes is to ensure that Reliability Coordinator can maintain an appropriate level of situational awareness. While the SDT believes that this will result in an additional burden on entities, it believes that this incremental increase is relatively minor and necessary for reliability. No change made. The SDT believes that the implementation time frame of 12 months is adequate. Nearly all, if not all, of the data that a Reliability Coordinator might need for reliability is already in place and telemetered to the Reliability Coordinator. The 12 month period will allow for any additional work that might be needed to be accomplished. Adoption of this standard does not create a massive new data transfer effort. No changes made.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td>Texas Reliability Entity</td><td>No</td><td>1)General: Recommend adding a Requirement 4 for RCs stating the RC shall notify entities that provided data per R2 when submitted data does not meet the specification and the nature of the deficiency.

2) R1: Use of the word "Provisions" in 1.2 is unclear in the context of this sub-requirement. Is it meant that the RC shall provide a tool (such as a web portal) for entities to notify the RC of Protection System and Special Protection System status? Or is it meant that the RC shall identify how notification should be made? If the latter, the word "provisions" should be replaced by "specifications". (Same comment was made for TOP-003-3, R 1.2)</td></tr>
<tr><td colspan="3">Response: 1) The SDT believes that the requirements are written such that the onus for performance is on the Reliability Coordinator. Therefore, the Reliability Coordinator will have every reason to be continually checking the data for accuracy or any deficiencies and that this becomes a technicality that does not rise to the level of a mandatory standard. No change made.

2) “Provisions” allows for multiple solutions – the standard only states what must be done, not how it must be accomplished. No change made.</td></tr>
<tr><td>Georgia Transmission Corporation</td><td>No</td><td>(1) GTC disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity if determined to be BES.
(2) Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly impact reliability, are redundant, and handle data requests and submittals.</td></tr>
<tr><td colspan="3">Response: (1) Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made.</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
(2) This requirement codifies the requirement to make available the data necessary to assure reliability and to address specific issues raised in the NOPR. The SDT does not agree that these are administrative requirements. No change made.		
NV Energy MidAmerican Energy	No	In R2 and R3, there is no specificity as to the allowable time for an entity to satisfy a new or modified data supply specification from the RC. As well, there is lack of precision in the use of the term "mutually agreeable" in 3.1 to 3.3. We recommend allowance of a time period, perhaps 90-180 days, for an entity to become fully responsive to requests from the RC for new data or modifications to existing reporting requirements.
Response: No timeframe is specified because each request may involve a different timeframe. The SDT believes that the Reliability Coordinator and the recipient entity will determine a reasonable timeframe on a case-by-case basis. No change made. "Mutually agreeable" allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can't force a solution on the other entity when that entity may not be physically capable of performing. No change made. The SDT believes that it would be self-defeating to specify a specific time period as each situation is different. The requirements as written allow the needed flexibility for this. No change made.		
SERC OC Review Group	Yes	1) The proposed R1.7 in the rationale is not listed in the document. 2) For the entity receiving a data request, it is preferred some language to be added that allows the entity supplying the data to coordinate the request to ensure a sufficient reliability need. Possible language as used in MOD- 001-02, R5 "Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider shall..."

Organization	Yes or No	Question 4 Comment
Response: 1) The rationale box has been corrected to read "Proposed Requirement R3, Part 3.3 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks." This directly addresses Paragraph 92 of the NOPR. 2) The standard gives the Reliability Coordinator the power to request anything needed for reliability. The Reliability Coordinator is not required to demonstrate the need for this data, as, by definition, the Reliability Coordinator is the function charged with preserving the reliability of the interconnected power system. No change made.		
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	Should proposed Requirement 1.2 be included in IRO-010-2 or in a PRC requirement? Southern believes that the SDT should consider if this requirement is better suited for PRC standards. The previous version included Requirement 1.4: "Process for data provision when automated Real-Time system operating data is unavailable." It is unclear why the SDT removed this sub part from the proposed IRO-010. Please provide the SDT's rationale for removing because there are times with the automated methods of providing data are unavailable.
Response: This standard is just a request for data with one 'piece' being Protection System data. It does not deal with the elements or requirements of Protection Systems which are the focus of PRC standards. No change made. This language was deleted because this situation is now covered in approved EOP-008-1, Requirement R1, Part 1.6.2. No change made.		
Peak Reliability	Yes	R1.1: Does "external data" mean one RC has the authority per this Requirement to request data from another RC? R2: The "mutually agreeable" language is potentially problematic, as it is unclear how the RC will receive the data if they cannot reach agreement on the format. Using "a clearly defined format" would be better. IRO-010-1a had a very important statement in R1.4 - "Process for data provision when automated Real-Time system operating data is unavailable." That is important

Organization	Yes or No	Question 4 Comment
		to have a common understanding of expectations and a plan for data delivery even when the automated system is unavailable. This should be added back to the Standard.
Response: R1.1: Yes, it does. R2: Mutually agreeable" allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can't force a solution on the other entity when that entity may not be physically capable of performing**.** No changes made IRO-010-1a R1.4: This language was deleted because this situation is now covered in approved EOP-008-1, Requirement R1, Part 1.6.2. No change made.		
ReliabilityFirst	Yes	ReliabilityFirst submits the following comments for consideration: 1. Requirement R1, Part 1.1 - The phrase "as deemed necessary" is ambiguous and leaves the requirement open to interpretation and therefore, difficult to enforce. To provide specificity, the requirement should state "... including sub-100 kV but greater than 50 kV data". This language is consistent with the NERC BES definition, and has a technical justification developed by that SDT.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process or that are over 50 KV, it is also true that there may be sub-100 kV points that are not needed as part of the BES or over 50 kV but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made.		
American Transmission Company	Yes	R1, R2 - N/A R3 - ATC agrees with the proposed Requirement R3, however, ATC suggests the requirement be reworded as follows to provide clarity and consistency with currently effective Requirement R3 from Reliability Standard IRO-010-1a: "R3. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission

Organization	Yes or No	Question 4 Comment
		Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications, to the Reliability Coordinator with which it has a reliability relationship, using a mutually agreeable:" 3.1 Format 3.2 Process for resolving data conflicts 3.3 Security protocol"
Response: The SDT does not believe that this suggestion adds clarity. No change made.		
Tri-State Generation and Transmission Association, Inc.	Yes	Tri-State believes R1.1 is written too vague and open ended by stating "as deemed necessary by the RC." Tri-State would like for the team to rewrite that sub-requirement to clarify the intent.
Response: The SDT believes that the Reliability Coordinator is in the best position to determine what data it needs and has written the requirement to allow for that. No change made.		
Salt River Project	Yes	SRP suggests that the RC determines the data obligations listed in R3 Part 3.1, 3.2, and 3.3. The RC is making the request for data so they should provide the format they need the data. Furthermore, if this is determined between each entity and the RC there may be multiple different formats, processes for resolving data conflicts, and security protocols that the RC will need to coordinate. If the RC determines the obligations they would all align.
Response: "Mutually agreeable" allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can't force a solution on the other entity when that entity may not be physically capable of performing. No changes made.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 4 Comment
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI supports comments posted by the SERC OC Work Group
MRO NERC Standards Review Forum	Yes	
PPL NERC Registered Affiliates	Yes	
Bureau of Reclamation	Yes	
FirstEnergy	Yes	
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Manitoba Hydro	Yes	
Exelon Companies	Yes	
Xcel Energy	Yes	
PNMR	Yes	

Organization	Yes or No	Question 4 Comment
David Kiguel	Yes	
PJM Interconnection	Yes	
Austin Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Hydro One	Yes	
Hydro One	Yes	
INDN - Independence Power & Light	Yes	
Response: Thank you for your response.		

5. **Do you agree with the changes made to proposed IRO-014-3? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has responded to comments requesting clarification and made numerous changes due to industry comments:

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact other Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

Requirement R1, Part 1.1: Criteria and processes for notifications .

Requirement R1, Part 1.5:

Requirement R1, Part1.6: Provisions for periodic communications to support reliable operations.

R3.

R4:

R5: Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators.

R6: Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency.

R7: Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.

R9: Each Reliability Coordinator shall assist Reliability Coordinators, if requested, provided that the requesting Reliability Coordinator has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	In Measure M1, for consistency remove the "s" from "notifications" so that the language matches that of R1, or add an "s" to "notification" in R1. To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes. To be consistent with the format of other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention. Requirements R2 and R4, as well as R1 sub-Part 1.1, indicate “and the process to follow in making those notifications.” Drafting Teams should focus on developing results-based standards.
Response: Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure. The SDT is striving to develop results-based standards.		
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc. Florida Municipal Power Agency	No	R1 - Change the word “other” to “adjacent.” R1.5 - Similar language was removed from IRO-001-1.1 R3 with the justification “The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act.” The same logic should be applied here and this requirement should be deleted. R1.6 - Is the intent for this requirement for adjacent RC’s to have a weekly call or that all RC’s within the Eastern Interconnection participate in a weekly call? Change R1.6 to state “at least weekly” to synchronize with R4.

Organization	Yes or No	Question 5 Comment
		R2 - Concern with term “Operating Plans” utilized throughout proposed Standards. We would recommend to remove this entire requirement since it is strictly an administrative requirement with no reliability benefit. R2.1 - Many of the new requirements imply daily creation of Operating Plans, yet this requirement states annual review. We would recommend to remove this requirement since it is strictly an administrative requirement with no reliability benefit. R2.2 - Seems to imply that each updated Operating Plan needs written agreement and we don’t believe that adds to reliability. We believe documents should be reviewed and updated as necessary. The way this requirement is written, if any modifications are made to an Operating Plan, a written agreement is needed. We would recommend to remove this requirement since it is strictly an administrative requirement with no reliability benefit. R2.3 - We would recommend to remove this entire requirement since it is strictly an administrative requirement with no reliability benefit. R5 - What is the driver to change from Adverse Reliability Impact to the term Emergency? Seems to move away from focusing on IROL type scenarios. As defined, the term Emergency refers to “any abnormal system condition that requires automatic or immediate manual action...” The use of this term is too broad. We have a concern that too much communication may be required for situations that do not need to be communicated between RCs. We would recommend keeping the term Adverse Reliability Impact. Please provide examples of instances where you would want the RC to RC communication to take place. Also provide examples of what is not considered an Emergency. R5-R9 What situation or need is the SDT trying to fix with these requirements? The term “Emergency” could be pulling in balancing actions instead of reliability needs. These requirements are inter-related and language seems to add confusion. This series of requirements tends to deal with disagreement between RCs and not the

Organization	Yes or No	Question 5 Comment
		focus of developing a coordinated action plan to resolve the Emergency. Language in current standards seems to be a better fit. R6, R8, and R9 seem duplicative. Existing language in IRO-016-1 for communication was more cooperative and the new language is more directive driven. We believe there should be a requirement that the problem is discussed and a coordinated action plan be developed (language in existing IRO-016-1). The term action plan is utilized in R7 which is a good term for Real-time Assessment, but other requirements utilize Operating Plan. R9 - What does implemented its emergency procedures mean? Is this related to the Operating Plan or action plans? It uses the term "requesting entity"...does this refer to a situation when a BA/TOP requests assistance from the RC and their RC requests assistance from another RC? Or does "requesting entity" refer to the requesting RC? It should explicitly state requesting RC if that is what is meant. Why is "emergency" not capitalized in this requirement?

Response: R1: The SDT agrees and has made the suggested change. See summary consideration for revision.

R1.5: The SDT agrees and has deleted the requirement. The SDT believes that proposed IRO-001-4, Requirement R1 and the language to 'act or direct others to act" covers this situation.

R1.6: The SDT has deleted Requirement R4 and revised requirement R1, Part 1.6 to address comments. The SDT does not believe that this is an administrative requirement and provides a benefit to reliability. See summary consideration for revision.

R2: An Operating Plan is defined as "A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes". This is the document that will contain the actions necessary to ensure reliability. The SDT believes this is the correct use of the term and that it correctly addresses the reliability need. The SDT does not consider this an administrative requirement. No change made.

R2.1: This requirement ensures proper attention is provided to the Operating Plans, Procedures, and Processes. No change made.

Organization	Yes or No	Question 5 Comment
R2.2: The requirement states that written agreement is required. Any Reliability Coordinator required to take action needs to be aware of the requirement so that it is able to take the prescribed actions and agrees to do so. The SDT believes this needs to be acknowledged in writing and that this is not strictly an administrative requirement. No change made. R2.3: If a Reliability Coordinator is required to take action per an Operating Plan, it needs to be aware of the requirement. Requirement R2 Part2.3 ensures that the Reliability Coordinator knows its responsibilities. The SDT does not consider this a strictly administrative requirement. No change made. R5: The driver to change from Adverse Reliability Impact to Emergency is contained in the rationale. An example of where the SDT could see Reliability Coordinator to Reliability Coordinator communication would be any time it identifies an Emergency. And an example of what is not considered an Emergency is an abnormal situation that does not require automatic or immediate manual action. No change made. R5 – 9: The situation or need addressed by the SDT in Requirements R5 through R9 is the identification of Emergencies and the actions to take should a disagreement arise between Reliability Coordinators. No change made. R6, 8, and 9: Requirements R6 and R8 speak to instances where a disagreement occurs between Reliability Coordinators around the existence of an Emergency. Requirement R9 addresses the need to provide emergency assistance after the requestor has exhausted its remedies. No change made. IRO-016-1: The SDT felt the cooperative dialogue referenced in approved IRO-016-1 would take place during the execution of proposed IRO-014-2 Requirement R5, identifying an expected or actual Emergency and notifying other impacted Reliability Coordinators. If during that notification, disagreement arises, proposed IRO-014-2 Requirements R6 – R8 come into play. No changes made. R7: The action plan in Requirement R7 is for those unique times when a disagreement arises between Reliability Coordinators and a plan needs to be developed to address the situation. No change made. R9: In Requirement R9 the term implemented means the requestor has taken all actions they could and now requires assistance. It does not matter whether it is an Operating Plan or an action plan. The requestor has run out of options and is seeking help. This request is between Reliability Coordinators. To provide greater clarity, the SDT has changed ‘entity’ to ‘Reliability Coordinator’. See summary consideration for revision.		

Organization	Yes or No	Question 5 Comment
MRO NERC Standards Review Forum	No	R1 requires RCs to have Operating Plans to inform "... other RC Areas...". Please note that WECC and TRE only have one RC within their Regions (Peak Reliability and ERCOT, respectfully). Where the Eastern Interconnection has 13 RCs, should this type of Requirements be removed and set up similar as IRO-006-EAST-001? This may also be applicable to R9. R1, R2 and R3 an Operating Plan is defined as "A DOCUMENT that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes". There is no reliability benefit to list Operating Procedures or Operating Processes since they are components of an Operating Plan. Recommend "Operating Procedures or Operating Processes" be deleted.
Response: R1: The intent of Requirement R1 is to reinforce coordination between entities. The requirement does just that. Standards are to be written on a continent-wide basis where possible. Neither ERCOT nor Peak Reliability has commented that this requirement doesn't or can't apply to them. No change made. The SDT believes that an entity should have the flexibility to use any of the 3 identified documents to fulfill this requirement. No change made.		
SERC OC Review Group Associated Electric Cooperative, Inc. - JRO00088	No	In R4, recommend replacing "other" with "adjacent" and removing part of sentence "within the same interconnection." Current: "Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement R1, Part 1.6) with other Reliability Coordinators within the same Interconnection." Suggested: "Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement R1, Part 1.6) with adjacent Reliability Coordinators."
Response: The SDT has deleted Requirement R4 and revised Requirement R1, Part 1.6 to address various comments. See summary consideration for revision.		

Organization	Yes or No	Question 5 Comment
Dominion	No	Dominion does not see a distinct difference between sub-requirements 1.3 and 1.4. We believe that periodicity infers the deadline. Dominion finds R1.5 to be administrative in nature and therefore do not support inclusion of this sub-requirement. IRO-001-4@R1 already requires the RC to act or direct others to act, to ensure the reliability of its Reliability Coordinator Area. This requirement should be included in whatever authority document the RC provides to its System Operators relative to the function of Reliability Operations and the Functional Entity of Reliability Coordinator (per Functional Model V5). Dominion finds R1.6 to be administrative in nature and therefore do not support inclusion of this sub-requirement. While Dominion agrees that each Reliability Coordinator should be required to participate in agreed upon conference calls and other forums with adjacent Reliability Coordinators we do not agree with the establishment of a minimum requirement. Dominion finds R4 to be administrative in nature and therefore do not support inclusion of this requirement. While Dominion agrees that each Reliability Coordinator should participate in agreed upon conference calls and other forums with adjacent Reliability Coordinators we do not agree with the establishment of a minimum (such as weekly) requirement. We could support if the phrase "at least weekly (per Requirement R1, Part 1.6)" were removed. Dominion does not agree with use of the term Emergency in requirements 5 through 8. Part of the definition of the term includes the phrase "Any abnormal system condition that requires automatic or immediate manual action…". We do not believe that the intent of Standard IRO-016-1@R1 was to wait until immediate action was necessary for the Reliability Coordinator to notify other Reliability Coordinators. We believe the intent was to make notification upon recognition of conditions that indicate a potential, expected, or actual problem. We could support if the words potential or expected were used in conjunction with the term Emergency.

Organization	Yes or No	Question 5 Comment
		Alternatively, we could support language similar to that used in TOP-001-3, Requirement 8.
Response: Periodicity: The SDT believes the commenter is referring to proposed IRO-010-2. Please see response to q4. R1.5: The SDT agrees and has deleted the requirement. R1.6: This is not a new requirement. Approved IRO-014-1, Requirement R1, Part 1.7 currently requires weekly conference calls. The Reliability Coordinators are already doing this and consider it an important concept for reliability. The SDT has revised requirement R1, Part 1.6 to respond to comments. See summary consideration for revision. R4: The SDT has deleted Requirement R4. R5 – R8: The SDT agrees that there should be consistency amongst standards and has changed proposed IRO-014-1, Requirement R5 to agree with the wording in proposed TOP-001-3, Requirement R8. Corresponding changes have been made to proposed IRO-014-2, Requirements R6 through R8. See summary consideration for revisions.		
Duke Energy	No	R1: We suggest changing “may impact other Reliability Coordinator Areas,” to “may impact adjacent Reliability Coordinator Areas.” This revision will reduce ambiguity on the expectations of the RC. Also, we suggest using only the term “Operating Plan” in this standard instead of the use of “Operating Procedures, Operating Processes, and Operating Plans.” We feel that Operating Processes and Operating Procedures are inherent in the definition of Operating Plan, and to list them out in this manner seems to indicate otherwise. R1.5: Similar language was removed from IRO-001-1.1 R3 with the justification “The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act.” The same logic should be applied here and this requirement should be deleted. R2: See comment above regarding the use of the term “Operating Plan.”

Organization	Yes or No	Question 5 Comment
		R3: Duke Energy feels fails to see the differences in the responsibilities of this requirement from those addressed in R2 and R3 of the proposed IRO-010-2. We request that a distinction be made, or suggest the removal of this requirement, as it appears to be duplicative in nature. R4: Duke Energy suggests the removal of this requirement. We feel that a re-wording of R1.6 to the following would satisfy the responsibility, without the necessity of having a specific requirement for participation on conference calls.”R1.6: Provisions to schedule and participate in weekly conference calls.” R5: Duke Energy is concerned particularly with the use of the terms “Emergency” and “Impacted” in the proposed requirement. The use of the current definition of “Emergency” would result in a substantial amount of notifications to impacted RC(s). An argument could be made, that any action that an RC takes could have a ripple effect that would then prompt notification to impacted RC(s) in an inordinate amount of instances. Also, the term “Impacted” is too broad, and should be more narrowly defined. We suggest reverting back to the old language (Adverse Reliability Impact), as the proposed language does not appear to be selective enough in nature. R6: Duke Energy questions how an auditor is going to measure compliance with the phrase “shall operate as though the problem exits”. We suggest reverting back to the currently effective language of “operating to the most limiting parameter” as we feel this language is more effective at resolving possible disputes between RC(s). R7: Duke Energy suggest the following revision: ”Each Reliability Coordinator that identified an Emergency shall develop an action plan to resolve the Emergency .” We believe that no matter the circumstances, even if a dispute exists between RC(s), if an RC believes that an Emergency situation exists, the RC identifying the Emergency should be required to develop an action plan to mitigate said Emergency. R8:Duke Energy suggest the following revision: ”Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency, unless such actions would violate safety, equipment,

Organization	Yes or No	Question 5 Comment
		regulatory, or statutory requirements." We believe that no matter the circumstances, even if a dispute exists between RC(s), the impacted RC(s) should implement the action plan developed to mitigate the Emergency identified by the identifying RC. R9: We are unclear as to the need for the phrase "provided that the requesting entity has implemented its emergency procedures". A requesting RC may not have an emergency procedure in place to mitigate the issue at the time of the event. We believe the intent of this requirement should be for RC(s) to help one another unless their assistance would violate safety, equipment, regulatory, or statutory requirements. As such, we suggest the following revision: "Each Reliability Coordinator shall assist Reliability Coordinators, if requested, unless such actions would violate safety, equipment, regulatory, or statutory requirements."

Response: R1: The SDT agrees and has replaced "other" with "adjacent". See summary consideration for revision.

The SDT believes that an entity should have the flexibility to use any of the 3 identified documents to fulfill this requirement. No change made.

R1.5: The SDT agrees and has deleted the requirement.

The SDT believes that an entity should have the flexibility to use any of the 3 identified documents to fulfill this requirement. No change made.

R3: Proposed IRO-010-2 addresses the collection of data. Proposed IRO-014-3 Requirement R3 speaks to actions spelled out as a result of the collected data integration. No change made.

R4: The SDT has deleted Requirement.

R5: The SDT moved from 'Adverse Reliability Impact' to 'Emergency' for consistency with other similarly worded standards and to bring the requirement to a more inclusive state. Using the term 'impacted' will limit the number of communications required. No change made.

R6: An Auditor will use the suggested evidence outlined in Measure M6 to assess compliance. You may very well operate to the most limiting parameter. What the requirement is saying is that you cannot deny the condition exists and do nothing. The SDT encourages you to submit comments to the posted RSAW to facilitate any changes. No change made.

Organization	Yes or No	Question 5 Comment
R7: Reliability Coordinators develop action plans now for identified Emergencies. This requirement addresses those unique times when not all impacted Reliability Coordinators agree. No change made. R8: The SDT does not believe that the suggested change adds clarity. No change made. R9: The intent of Requirement R9 is to require the requesting Reliability Coordinator to have attempted mitigation, if possible, before asking adjacent Reliability Coordinators to act. No change made.		
SPP Standards Review Group	No	Replace 'the problem' with 'an Emergency' in Requirement R6.
Response: The SDT agrees and has made the suggested change. See summary consideration for revisions.		
ACES Standards Collaborators	No	(1) We question the rationale for R6 and ask the SDT to provide examples or guidance in the technical reference guide for scenarios where RCs would disagree whether there is an Emergency or not in an Interconnection.
Response: The rationale for the requirement is that should a disagreement arise, there needs to be a process in place to guide the participants in their ensuing actions. Tie-line loadings are an example of situations where this may arise. No change made.		
ISO/RTO Standards Review Committee (SRC)	No	R2 and 4, as well as the portion of 1.1, which indicates, "and the process to follow in making those notifications" are not results-based. We encourage NERC SDTs to focus on developing results-based standards.
Response: The SDT is striving to develop results-based standards. Requirement R1, Part 1.1 has been revised. The SDT believes there is a reliability-based need for Requirement R2. Requirement R4 has been deleted.		
PNMR	No	IRO-014-1 R3 requires the PC and TP to provide its Planning Assessment to the RC. The rationale states that a summary of the TPL-001-4 assumptions and results would satisfy this requirement. Including this requirement in the IRO is mixing the Operations and Planning Horizons. The drafting team should remove this requirement from IRO-014-1 and recommend that TPL-001-4 R8 be updated to include the RC.

Organization	Yes or No	Question 5 Comment
Response: The SDT believes this comment refers to proposed IRO-017-1. Please see responses to q6.		
David Kiguel	No	R9: How will the RC that requested assistance demonstrate and how will the RC whose assistance was requested verify that the requesting entity has implemented its emergency procedures?
Response: The SDT believes that a Reliability Coordinator will not ask for assistance without having first instituted its own procedures. Normally, agreements are already in place to cover this situation. Things can, and will, be sorted out after the fact as to whether the proper protocols have been followed.		
Electric Reliability Council of Texas, Inc.	No	R3 and R5 appear to be redundant. R5 would be under the notifications identified in R3. If the SDT does not believe R1 is explicit enough to identify emergencies under R1.1, then clarify R1 so that R5 can be deleted. While other requirements use the term “impacted” to limit Emergency to just those that raise to the level of needing coordination with other RCs, R7 is silent and although infers, if read solitarily, could create the issue of interpreting all “Emergencies” which is not the intent. ERCOT suggests including language that limits R7 scope to only those Emergencies that rise to the level of needing coordination with other RCs, since the SDT has chosen to replace Adverse Reliability Impact with Emergency as that term includes local Emergencies as well. R9 (and TOP-001-R7) make sense from the context of having additional circumstances arise in real time that were not “planned” actions. It allows for assistance outside of agreed upon and coordinated plans to take place. This is accurate in that you cannot plan for every type of occurrence that is possible. If this is the context that the SDT imagined, ERCOT recommends capturing such concept within the RSAW. If it is not, ERCOT recommends deleting both requirements as it is redundant to the requirements requiring actions per plans to be taken. It would be beneficial to see the auditor’s approach to expectations associated with RCs that are in separate Interconnections connected via DC Ties in the RSAW for IRO-

Organization	Yes or No	Question 5 Comment
		014. DC Ties are viewed as resources or loads within the ERCOT Interconnection. While R4 is clear on the issue, the other requirements are vague.
Response: The SDT has deleted Requirement R3. The SDT agrees and has made the suggested change. See summary consideration for revision. R9 and DC ties: The RSAWs for this project have been posted and are available for comment.		
Texas Reliability Entity	No	1) R1: Use of the word "Provisions" in 1.6 is unclear in the context of this sub-requirement. Is it meant that the RC shall provide a tool (such as a conference bridge) for conduct weekly conference calls? Or is it meant that the RC shall identify how the calls will be scheduled and conducted? If the latter, the word "provisions" should be replaced by "specifications". 2) R4: R4 seems to contradict R1. R1 requires each RC to have Operating Procedures, Processes or Plans for actions that may impact other RC areas; including provisions for weekly conference calls. R4 limits the requirement for RCs to participate in weekly conference calls to other RCs within the same Interconnection. Is it the SDT intent to have RCs have weekly conference calls with other RCs in the same Interconnection only? We recognize this may not be an issue outside of the ERCOT region, but we seek clarification from the SDT. 3) R's 6, 7 and 8: Requirements 6, 7 and 8 seem to exclude the situation where RCs agree. All the same actions should be taken for 6, 7 and 8 regardless of whether RCs agree or disagree on the existence of an Emergency. 4) R8: The purpose of the standard is to preserve the reliability benefits of interconnected operations. As such, for R8, each RC's implementation of another RC's action plan should have a required time frame. In addition, if the RC does not implement the action because such actions violate safety, equipment, regulatory or statutory requirements they should be required to notify the RC who developed the action plan within a required time frame.

Organization	Yes or No	Question 5 Comment
Response: The SDT has revised Requirement R1 Part 1.6 for clarity. See summary consideration for revision. 2) The SDT has deleted Requirement R4 and revised Requirement R1, Part 1.6 in response to this comment and those of others. See summary consideration for revisions. 3) The SDT believes that Requirement R5 addresses the situation in question since the entity must declare the Emergency in order to move on to Requirements R6 to R8. No change made. 4) The SDT believes that the Reliability Coordinator developing the plan will include a timeframe for implementation in the plan. No change made.		
Arizona Public Service Company	Yes	IRO-014 R9: There are one too many “be”s, “cannot be physically be implemented”
Response: The SDT agrees and has made the suggested change. See summary consideration for revisions.		
Peak Reliability	Yes	R1.6: “Provisions for weekly conference calls” should be “Provisions for weekly conference calls with Reliability Coordinators within the same Interconnection” to match the language of R4. R2: The current Standard allows for 36 months. It is unclear why this changed. There doesn’t seem to be a reliability issue that would precipitate this change. Also, R2.2 should be changed to language consistent with EOP-006-2 R2 & R4. R5 & R7: “Each Reliability Coordinator that identified an Emergency” should be changed to “Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area” If one RC identifies and Emergency in another RC’s Area, and there is disagreement, the first RC should not be required to develop a plan. R9: “unless such actions cannot be physically be implemented or would violate safety, equipment, regulatory, or statutory requirements” should be changed to “unless such actions would cause adverse reliability impacts or would violate safety, equipment, regulatory, or statutory requirements”.

Organization	Yes or No	Question 5 Comment
Response: The SDT has revised Requirement R1 Part 1.6. See summary consideration for revision. R2: The SDT believes that such an important concept requires annual review. No change made. R2.2: The SDT believes that while the words are not exactly the same that the bottom line will be the same and that the suggested change therefore, adds no additional clarity. A written agreement implies a review No change made. R5/R7: The SDT believes that it is implicit in the requirements (and the Functional Model) that a Reliability Coordinator can only declare an Emergency in its own Reliability Coordinator Area and that the suggestion is basically redundant. However, to improve clarity, the SDT has made the suggested change. See summary consideration for revision. R9: The SDT disagrees. The indicated language was in proposed IRO-014-2 which was Board-approved but is proposed for rejection in the FERC NOPR. The current language is consistent with other proposed requirements in this project. No change made.		
Colorado Springs Utilities	Yes	No Comments
PacifiCorp	Yes	
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	
PPL NERC Registered Affiliates	Yes	
Bureau of Reclamation	Yes	

Organization	Yes or No	Question 5 Comment
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
Rayburn Country Electric Cooperative	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Exelon Companies	Yes	
Xcel Energy	Yes	
ReliabilityFirst	Yes	
PJM Interconnection	Yes	
Consumers Energy	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	

Organization	Yes or No	Question 5 Comment
Independent Electricity System Operator	Yes	
Hydro One	Yes	
INDN - Independence Power & Light	Yes	
Georgia Transmission Corporation	Yes	
Salt River Project	Yes	
NV Energy	Yes	Most of these requirements are predicated on the idea that multiple RC entities exist within a particular Interconnection. Accordingly, most of the requirements will be inapplicable to the WECC and TRE areas.
MidAmerican Energy	Yes	
Response: Thank you for your response.		

6. **Do you agree with the changes made to proposed IRO-017-1? 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:

Purpose: To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.

R1, Part 1.1.2: Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s) .

R1, Part 1.3: Define the process to evaluate the impact of Transmission and generator outages within its Wide Area.

R1, Part 1.5:

R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process.

R4. Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	The Purpose needs to be revised to indicate that the outages are properly coordinated between whom? To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes.
Response: The SDT agrees and has revised the Purpose statement accordingly. See summary consideration for revisions.		

Organization	Yes or No	Question 6 Comment
Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure.		
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	R1.3 and R1.5 seem to be stating the same thing just using different language. Please clarify the difference between the 2 requirements. R1.1.2 - Recommend to delete the language “prior to submitting to RCs”. Each RC should be able to define their process to fit their area. M2 - Could an attestation from the RC that each TOP and BA followed the outage coordination process be evidence? A concern on what the evidence would look like if this was not feasible. R3 & R4 - The PC’s and TP’s planning horizon is Year One and beyond. They do not cover the Operations Planning time horizon, so how do R3 and R4 practically apply to the RC. The PC’s and TP’s have the responsibility to develop “corrective action plans” for identified issues or conflicts for the time frame they are studying. Recommend to strike R3 and R4 from this standard. If keeping R3, then it should be in the TPL standard, not the IRO standard.
Response: The SDT agrees and has deleted Requirement R1, Part 1.5. The SDT agrees has deleted “prior to submitting to Reliability Coordinators” from Requirement R1, Part 1.1.2 as suggested since the process document can be tailored in this fashion if desired by the Reliability Coordinator. See summary consideration for revisions. The SDT believes that the evidence list in measure M2 is not intended to be exhaustive and already contains provision for other evidence types by virtue of the “could include, but is not limited to” clause. The SDT is responding to issues raised in the FERC NOPR and in the IERP Report to expand the scope of outage planning to incorporate Reliability Coordinators into this planning process. However, the SDT agrees that the primary responsibility in the Near-term Transmission Planning Horizon is on Transmission Planners and Planning Coordinators, and has updated R4 as noted in the summary considerations. While the SDT agrees that R3 and R4 could be incorporated into a future version of TPL-001, the SDT believes that, due to timing, the requirements should be kept in IRO-017 until such a change occurs.		

Organization	Yes or No	Question 6 Comment
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 Georgia System Operations Georgia Transmission Corporation	No	Overall, Southern does not agree with this new outage coordination standard. This standard is expanding the responsibilities of the RC beyond that contemplated in the NERC Functional Model and NERC Glossary, which is current day and next day operations. As written, this requirement conflicts with the Functional Model and the NERC Glossary, which both clearly address the roles of the Reliability Coordinator. The Reliability Coordinator, according to the Functional Model, "receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis." Furthermore, the NERC Glossary notes that the Reliability Coordinator "is to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations." This definition indicates that the Reliability Coordinator's scope is for next day and real-time operations. Southern recommends that this standard be withdrawn from the project. If the SDT does not withdraw the standard, at a minimum, the SDT should modify the standard to address the following comments. The proposed subpart 1.5 requires RCs to document and maintain the specifications for outage analysis during the operations planning horizon, which is next day to one year out. We do recognize that the SDT's rationale provides the RCs with some discretion as to whether or not the RC desires to have specifications for outage analysis in the operations planning horizon; however Southern recommends adding language to subpart 1.5 to clearly state that the RC has discretion by adding ", if deemed necessary by the RC" to the end. Southern does not agree with R4 as it seems to imply that RCs conduct outage coordination assessments even beyond the operations planning horizon. Again, RCs are focused on real time and next day timeframes, not the Planning Assessment timeframe, and should not be required to coordinate solutions in the Planning Assessment timeframe. This requirement is expanding the responsibilities of the RC beyond that contemplated in the NERC Functional Model and NERC Glossary (see definition of RC), which is current day and next day operations. This requirement

Organization	Yes or No	Question 6 Comment
		should be removed, or, at a minimum, be revised to include "if deemed necessary by the RC". The existing TOP-002-2.1b R11 requires TOPs to perform seasonal studies to determine SOLs and to provide the results of those studies to its RC.
Response: The SDT is responding to issues raised in the FERC NOPR and in the IERP Report to expand the scope of outage planning to incorporate Reliability Coordinators into this planning process. However, the SDT agrees that the primary responsibility in the Near-term Transmission Planning Horizon is on Transmission Planners and Planning Coordinators, and has updated R4 as noted in the summary considerations. The SDT agrees and has deleted Requirement R1, Part 1.5. The SDT notes that approved TOP-002-2.1b, Requirement R11 is proposed for retirement. The SDT believes that no new reliability gaps are being created by this retirement due to new requirements included in proposed IRO-017-1, when coupled with requirements in approved FAC-014-2 Requirement R2 (determination of SOLs), proposed IRO-008-2/TOP-002-4 revisions (identifying SOL and IROL exceedances), approved MOD-001-2 Requirement R1 (TTC determination), and proposed IRO-017-1 (requiring joint development of solutions in the Near-term Transmission Planning Horizon, and strengthened coordination processes within the operations planning time horizon).		
Dominion	No	Dominion does not believe that sub-requirement 1.5 allows the Reliability Coordinator to request seasonal planning assessments if so desired. Instead it appears to require they do so. We suggest revising to read "Document and maintain the specifications for outage analysis during the operations planning horizon if desired."
Response: The SDT proposes to delete Requirement R1, Part 1.5 based on comments indicating duplicity with Requirement R1, Part 1.3, so the suggested edits are unnecessary.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, FMPA believes seasonal analyses to evaluate planned maintenance is an important reliability function that should not be lost and cannot be replaced by

Organization	Yes or No	Question 6 Comment
		"Planning Assessments". Recommend modifying R1.5 as follows: "Specify a periodicity, not less frequently than seasonally, of outage analyses during the operations planning horizon."
Response: See response to FRCC comments. While the SDT proposes to delete Requirement R1, Part 1.5, it is certainly permissible for a Reliability Coordinator to include seasonal assessments as part of its outage coordination process document, if it deems necessary.		
Duke Energy	No	R1: Duke Energy believes using the Operational Planning Horizon expands the RCs responsibility beyond next day operations and does not align with the responsibilities of an RC as defined in the NERC Functional Model. R1.1.2: Duke Energy suggests the following revision: "Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s)."Each RC should be able to define their process for submitting outage coordination data to fit their RC Area. R1.3/ R1.5: Duke Energy believes these two sub-requires are duplicative and suggests the removal of one of them. Please clarify the difference between the 2 sub-requirements. M2: Duke Energy suggests adding a provision that an attestation from the RC stating that their BA/TOP followed their RC Outage Coordination Process is acceptable evidence. R3/R4: Duke Energy recommends the removal of R3 and R4. The TPL Planning Assessments are not used in the Operations Planning horizon. Additionally, we fail to see the reliability based need for an RC to have the kind of analysis provided by a Transmission Planner/Planning Coordinator. The assessments made by a TP/PC are in located in the time horizon of 1-year and beyond, with some assessments potentially being as far as 20-years into the future. With the RC's

Organization	Yes or No	Question 6 Comment
		responsibility mainly focused on Real-time operations, we do not agree that providing the planning assessments alluded to in R3 and R4 is necessary.
Response: The SDT believes that the Reliability Coordinator involvement in coordination of future outages beyond the next-day horizon is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. The SDT also believes that the functional model should be revised in the future reflect this need. The SDT agrees and has deleted “prior to submitting to Reliability Coordinators” from Requirement R1, Part 1.1.2. The process document can be tailored as suggested if desired by the Reliability Coordinator. See summary consideration for revisions. The SDT agrees with the comment regarding overlap between Requirement R1, Parts 1.3 and 1.5, and proposes to delete Requirement R1, Part 1.5. The SDT believes that the evidence list in Measure M2 is not intended to be exhaustive and already contains provision for other evidence types by virtue of the “could include, but is not limited to” clause. No change made. The SDT is responding to issues raised in the FERC NOPR and in the IERP Report to expand the scope of outage planning to incorporate Reliability Coordinators into this planning process. However, the SDT agrees that the primary responsibility in the Near-term Transmission Planning Horizon is on Transmission Planners and Planning Coordinators, and has updated R4 as noted in the summary considerations.		
Bureau of Reclamation	No	Reclamation believes that Generator Operators should be included in the proposed outage coordination standard. Like TOP-003-1, IRO-017-1 should outline a specific continent-wide standard like the submission of planned generation outages over 50MW by noon on the day before the outage. The standard should acknowledge that generators may have unplanned outages due to safety concerns, equipment concerns, regulatory requirements, or statutory requirements.
Response: The SDT believes that Generator Operator data on planned outages will be incorporated into the process through the Balancing Authority. No change made.		
BC Hydro and Power Authority	No	The requirements as stated can be interpreted as the RC defines coordination processes and activities, and the TOP’s and BA’s follow. The responsibility for

Organization	Yes or No	Question 6 Comment
		coordination should reside with the TOP's and BA's, in order to manage system and regional impacts of outages. Transmission Operators and Balancing Authorities that already have coordination processes for managing outages within their jurisdictions and with neighbors, would have added requirements, however such practices are already well developed, taking into account standards, mutually agreed requirements and special needs of participants, in addition to system wide needs for communication to support assessments. Under TOP-002-2.1b, R1 and R4, Transmission Operators and Balancing Authorities are already required to coordinate, current-day, next-day and seasonal planning and operations which implies the requirement for outage coordination. While TOP-003-1 R2 and R3 provides more specific and explicit requirements to coordinate outages of voltage regulating equipment and telemetering and control equipment, it does not address the coordination of generation and transmission equipment. While TOP-003 may not (in current form) be comprehensive in its inclusion of equipment types for coordination, TOP-003 however should be the place to identify requirements for coordination of transmission and generation outages. R1 states requirements to convey outage information, but is silent on coordination. However, a revision to TOP-003 standard could place the requirements for determining coordination activities in the TOP's and BA's responsibilities. Nowhere in the IRO-017 is there a requirement for the RC to collaborate with the TOP and BA on defining processes to evaluate impact of outages, or the development of specifications for outage analysis. An RC driven coordination process does not account for differences and needs of TOP's and BA's, that have greater and/or mutual needs for practices not prescribed by RC needs. The requirements provide prescription that only addresses RC needs; involvement of governance (through the RRA involvement), collaboration, and emphasis on continuous improvement of processes would set a better standard, by requiring collaboration in the development of process requirements. The focus of IRO-017 should be on submission of outage information to support RC processes, including timelines for the submission of outages, practices for the communications of outages among the RC, TOP's and BA's, responsibility for assessment of system wide conflicts

Organization	Yes or No	Question 6 Comment
		through study assessment, and development of conflict resolution processes to support operations.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report, although this does not diminish the role of Transmission Operators and Balancing Authorities in that effort. The SDT suggests that the commenter review the mapping document to see how the cited requirements are being handle moving forward. No change made.		
SPP Standards Review Group INDN - Independence Power & Light	No	The recent trend at NERC is to eliminate subparts. Therefore, change the formatting on Requirement 1 Subparts 1.1.1 and 1.1.2 to bullets. We recommend that Requirement R3 be deleted in that it is redundant with TPL-001-4, Requirement R8. If the Reliability Coordinator has a need for the assessment, the Reliability Coordinator can request a copy of the assessment from the Planning Coordinator and Transmission Planner who are then obligated to provide a copy of the assessment to the Reliability Coordinator.
Response: The SDT does not agree that it is necessary to eliminate sub-parts and that the use of sub-parts here is appropriate. The SDT believes that proposed IRO-017-1 goes beyond approved TPL-001-4. Approved TPL-001-4, Requirement R8 does not explicitly cite the Reliability Coordinator as a receiving entity but would necessitate that the Reliability Coordinator submit a written request for the Planning Assessment. Proposed IRO-017-1, Requirement R3 makes it mandatory to include the Reliability Coordinator. Further proposed IRO-017-1 Requirement R4 necessitates Reliability Coordinator involvement in identifying solutions to identified issues. However, the SDT has updated Requirement R4 as noted in the summary considerations. The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document.		
ACES Standards Collaborators	No	(1) Requirement R2 needs to be clarified, as it leaves too much room for interpretation from auditors. What does “follow” mean? Does this mean to follow Operating Instructions? If so, then it would be redundant with IRO-001. If “follow”

Organization	Yes or No	Question 6 Comment
		means to have a copy of the RC outage coordination process, then it meets Paragraph 81 criteria as an administrative task. We recommend striking requirement as there are other methods for the RC to ensure that the TOP and BA will “follow” the RC instructions for outage coordination.
Response: The SDT agrees and has made the suggested change. See summary consideration for revisions.		
ISO/RTO Standards Review Committee (SRC)	No	R2 VRFs should be Medium, not Low. (note: CAISO does not agree with this comment). Requirement R1 requires the Reliability Coordinator to identify the roles and develop a process for coordinating outage plans between TOPs and BAs. However, the BA does not develop generator outage plans or schedules; it’s the GO that develops generator outage plans and submit to the BA for assessing resource-demand-interchange balance. Further, as indicated in the Functional Model, the RC:- Receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis. - Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability. We suggest the SDT consult the FMWG on the appropriate functional entities that should be responsible for coordinating outage plans, and revise R1 (and R2) accordingly.
Response: With no justification provided for the suggested change to the VRFs, the SDT is unable to respond to this request. The VRF/VSL Justification Document provides the reasoning for the SDT assignment of a Low VRF. No change made. The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. In addition, the data from the Generator Owners and Transmission Owners will be forwarded by the Balancing Authorities and Transmission Operators respectively. Specifics of the coordination mechanisms, which may vary depending on entity structure, can be detailed in the outage coordination process documents mandated by Requirement R1. No change made.		

Organization	Yes or No	Question 6 Comment
Bonneville Power Administration	No	Since this Standard only includes the operations planning horizon, BPA does not feel it is necessary or appropriate to include Planning Coordinator (PC) and Transmission Planner (TP) as applicable functions. BPA believes requirements R3 and R4 should be applicable to Transmission Operators (TOPs), but not TPs or PCs. BPA also feels that identifying Planning Assessment in this Standard creates a conflict by introducing the Planning Horizon into a Standard that should only cover an operations horizon. The Planning Assessments in TPL-001-4 are not the type of seasonal or outage planning assessments performed by TOPs. The TP would not be assessing planned outages in the Planning Assessment.
Response: The SDT has corrected the Time Horizon to include Long-term Planning to better reflect the intent of the standard. This will correctly incorporate Planning Coordinators and Transmission Planners. The SDT has also modified the language in Requirement R4 to clarify applicable entities, as noted in the summary comments.		
CenterPoint Energy Houston Electric LLC.	No	CenterPoint Energy believes that any coordination of a Planning Assessment between appropriate entities is covered in TPL-001-4 R2, R3, and R8. Furthermore, CenterPoint Energy feels the Reliability Coordinator is a Real-Time function per the NERC Functional Model and should not have a compliance responsibility in coordination of a Planning Assessment between the Planning Coordinator and Transmission Planner. CenterPoint energy recommends removing IRO-17-1 R3 and R4.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. The SDT believes that Requirements R3 and R4, which go beyond the scope of the approved TPL-001-4, could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document.		

Organization	Yes or No	Question 6 Comment
CPS Energy	No	"Transmission Planner" should be stricken from requirement R3, as the Transmission Planner is already obligated to provide the Planning Assessment to the Planning Coordinator through TPL-001-4. The requirement R4 should be stricken entirely, since this study is already performed and reported in the Planning Assessment required by TPL-001-4.
Response: The SDT has corrected the Time Horizon to include Long-term Planning to better reflect the intent of the standard. This will correctly incorporate Planning Coordinators and Transmission Planners. The SDT has also modified the language in Requirement R4 to clarify applicable entities, as noted in the summary comments.		
Ingleside Cogeneration LP	No	ICLP believes that this is a perfect example of a standard that should inherently assume that a mostly automated process exists. Most outage coordination already takes place through ISO-managed portals because of the convenience, data consistency, and security they provide. Instead of playing to the least-common denominator (i.e.; fully manual outage coordination), IRO-017-1 should be written in a manner that assumes that portals exist - rendering most of the requirements in this standard irrelevant.
Response: The SDT believes that it is tasked to specify requirements, not how an entity would comply with such requirements. While such portals may exist in many areas, it is not necessary to have such technological capabilities to achieve the reliability objectives of the requirement. No change made.		
American Transmission Company	No	ATC requests that the SDT consider making the following modifications: a. R1 - N/A b. R2 - ATC agrees with the proposed IRO-017-1 Requirement R2. c. R3 - To provide more specificity and flexibility, ATC suggests Requirement R3 be reworded as: "R3. Each Planning Coordinator and Transmission Planner shall make each new Planning Assessment available to impacted Reliability Coordinators and their Transmission Operator(s)." The revised language clearly indicates which Planning Assessment is provided and when. In addition, the language allows PCs and TPs to make a web-based version of the Planning Assessment and not require

Organization	Yes or No	Question 6 Comment
		conversion of the Assessment to a form that can be transmitted to applicable Reliability Coordinators by mail or email. Finally, ATC suggests that Transmission Operators be added as an applicable entity for receipt of the Assessment. d. R4 -ATC suggests removal of the proposed Requirement R4 entirely. The rationale is that the Reliability Coordinator should not have to resolve potential planned outage conflicts more than one year out with the Planning Coordinator and Transmission Planner. There are too many variables on this time scale that affect the answer. A better approach would be for the RC, TOP(s) and GOP(s) to resolve any outage conflicts, including moving or cancelling the outage, once the time window is within the “one year out” timeframe.

Response: (a. and b.) Thank you for your support.

c. The SDT does not believe that the suggested change adds any clarity. And the SDT does not believe that the Transmission Operator should be included in the requirement. The desired coordination is between the Reliability Coordinator, Planning Coordinator, and Transmission Planner and does not need to include Transmission Operators. No change made.

d. The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. No change made.

e. The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. The SDT has corrected the Time Horizon to include Long-term Planning to better reflect the intent of the standard. This will correctly incorporate Planning Coordinators and Transmission Planners. The SDT has also modified the language in R4 to clarify applicable entities, as noted in the summary comments. The SDT agrees that Requirements R3 and R4, which go beyond the scope of the approved TPL-001-4, could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document.

Organization	Yes or No	Question 6 Comment
Austin Energy	No	: City of Austin dba Austin Energy (AE) supports the separation of the Outage Coordination standard, though we believe it is not entirely necessary. R1 and R2 could be easily included in one of the other standards (where they were originally). AE believes R3 and R4 are unnecessary in their entirety and asks the SDT to remove them. AE does not understand the purpose they are trying to fulfill, as there is no mention of them in the mapping document. Further, AE believes R3 and R4 are redundant with requirements in TPL-001-4, which becomes enforceable on 1/1/15. TPL-001-4, R8 provides a mechanism for any entity with a reliability need to obtain a copy of the Planning Assessment. Through this requirement, the RC could certainly make a case for receiving copies from the PC and TPs. TPL-001-4, R4 Part 4.1 provides a mechanism for coordination, as necessary. Alternatively, IRO-017-1, R4 can be subsumed into IRO-017-1, R1, as any outage coordination should take place through the Transmission Operator. The RC can develop its R1 process to require the submittal of longer-term outages, if necessary, and outage conflicts would then be covered and resolved through R1 Part 1.4.
Response: The SDT believes that proposed IRO-017-1 goes beyond approved TPL-001-4. Approved TPL-001-4, Requirement R8 does not explicitly cite the Reliability Coordinator as a receiving entity but would necessitate that the Reliability Coordinator submit a written request for the Planning Assessment. Proposed IRO-017-1, Requirement R3 makes it mandatory to include the Reliability Coordinator. Further proposed IRO-017-1 Requirement R4 necessitates Reliability Coordinator involvement in identifying solutions to identified issues. However, the SDT has updated R4 as noted in the summary considerations. The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document.		
Liberty Electric Power, LLC	No	There is no language regarding which entities the plan will be "made available" to. Generators should be included on the list so they can plan outages knowing the process being used to approve or deny requests.

Organization	Yes or No	Question 6 Comment
Independent Electricity System Operator	No	Requirement R1 requires the Reliability Coordinator to identify the roles and develop a process for coordinating outage plans between TOPs and BAs. However, the BA does not develop generator outage plans or schedules; it's the GO that develops generator outage plans and submit to the BA for assessing resource-demand-interchange balance. Further, as indicated in the Functional Model, the RC:- Receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis. - Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability. We suggest the SDT consult the FMWG on the appropriate functional entities that should be responsible for coordinating outage plans, and revise R1 (and R2) accordingly.
Response: The SDT envisions that these details would be elaborated in the process document. No changes made.		
Oncor Electric Delivery LLC	No	Proposed Standard IRO-017-1 R3 states: "Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators." Oncor considers R3 to be a planning requirement that should not be included in IRO-017-1. This Requirement is redundant to approved Standard TPL-001-4 R8 and therefore is misaligned to the Paragraph 81 initiative Criteria B7 to eliminate redundant requirement. Oncor recommends the removal of IRO-017-1 R3.
Response: The SDT believes that proposed IRO-017-1 goes beyond approved TPL-001-4. Approved TPL-001-4, Requirement R8 does not explicitly cite the Reliability Coordinator as a receiving entity but would necessitate that the Reliability Coordinator submit a written request for the Planning Assessment. Proposed IRO-017-1, Requirement R3 makes it mandatory to include the Reliability Coordinator. Further proposed IRO-017-1 Requirement R4 necessitates Reliability Coordinator involvement in identifying solutions to identified issues. However, the SDT has updated Requirement R4 as noted in the summary considerations. The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document.		

Organization	Yes or No	Question 6 Comment
Hydro One	No	We believe that IRO 017 -1 needs more work. From an Ontario perspective the TP and PC do not coordinate outages.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. However, the SDT has modified Requirement R4 to clarify roles, as noted in the summary comments		
Lincoln Electric System	No	To avoid requiring the distribution of the Planning Assessment within separate standards, LES recommends that requirement IRO-017-1 R3 be removed altogether. TPL-001-4 R8 already allows for “any entity that has a reliability related need” to submit a request for the Planning Assessment. Dividing what is essentially the same requirement between two separate standards introduces unnecessary compliance risk for registered entities. If the drafting team believes the RC should be identified as a recipient, then TPL-001-4 should be revised to reflect this change. As currently drafted, R4 would require the Planning Coordinator and Transmission Planner to coordinate solutions with the RC for issues identified during planned outages in the Planning Assessment which can extend into the Planning Horizon. To ensure the correct timeframe is reflected in the standard, LES recommends revising R4 to specify that the PC/TP/RC should only coordinate solutions in the Operations Planning Horizon (Operations planning horizon is next-day to one year out), and not outside the Operations Planning Horizon into the Planning Horizon. The RC should coordinate solutions within the RC area.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. Approved TPL-001-4, Requirement R8 does not include the Reliability Coordinator. However, the SDT has corrected the Time Horizon to include Long-term Planning to better reflect the intent of the standard. This will correctly incorporate Planning Coordinators and Transmission Planners. The SDT has also modified the language in Requirement R4 to clarify applicable entities, as noted in the summary comments.		

Organization	Yes or No	Question 6 Comment
Electric Reliability Council of Texas, Inc.	No	ERCOT believes “develop” in R1 is unnecessary and only creates confusion when auditing and enforcing. To implement and maintain addresses the reliability concept. Replace R1.5 “document and” with “maintain”, which is sufficient. Document is purely administrative. M1 infers a requirement by including “dated”. By having current specifications for outage analysis during the operations planning horizon should be sufficient in itself for compliance. If a date is required, it should be in the requirement. R3 should be incorporated into TPL-001-4 R8 if it is necessary. R4 is vague and may be duplicative with TPL-001-4 R2.7 which requires development of a Corrective Action Plan whenever system performance (with known outages modeled) doesn’t meet Table 1 requirements. R1.5 should address evaluation of outages in an operations planning timeframe. If more specificity is needed to address within XX amount of days in advance, that should be clarified.
Response: The SDT believes that the terminology in the requirement is correct as written. Develop is a necessary part of the equation. No change made. The SDT proposes to delete Requirement R1, Part 1.5 based on comments indicating duplicity with Requirement R1, Part 1.3, so the suggested edits are unnecessary. The SDT believes that proposed IRO-017-1 goes beyond approved TPL-001-4. Approved TPL-001-4, Requirement R8 does not explicitly cite the Reliability Coordinator as a receiving entity but would necessitate that the Reliability Coordinator submit a written request for the Planning Assessment. Proposed IRO-017-1, Requirement R3 makes it mandatory to include the Reliability Coordinator. Further proposed IRO-017-1 Requirement R4 necessitates Reliability Coordinator involvement in identifying solutions to identified issues. However, the SDT has updated R4 as noted in the summary considerations. The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement		

Organization	Yes or No	Question 6 Comment
R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document. Incorporation of 'dated' in measures is an accepted concept. No change made.		
Salt River Project	No	Per R1, the RC must develop an Outage Coordination process that will take many aspects out of the BA & TOPs hands, specifically flexibility for units or crews on their start and end times. This decreased flexibility can lead to increased costs. R3 is burdensome to provide textual summaries of load flow studies and the assessment information for those studies. There are also concerns over distributing assessment information externally. R4 requires the Transmission Planner to coordinate solutions for issues or conflicts with planned outages. Outage coordination can be managed by Transmission Operators. SRP suggests allowing for Transmission Operators to coordinate solutions with the RC and PC.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages beyond the next-day horizon is necessary to respond to issues raised in the FERC NOPR and in the IERP Report, although this does not diminish the role of Transmission Operators and Balancing Authorities in that effort. No change made. Requirement R3 requires the distribution of the Planning Assessment which is typically a text document with summaries of load flow studies and thus shouldn't be burdensome. No change made. The SDT does not believe that the Transmission Operator should be included in the requirement. The desired coordination is between the Reliability Coordinator, Planning Coordinator, and Transmission Planner and does not need to include Transmission Operators. No change made.		
NV Energy MidAmerican Energy	No	R3 and R4: The Planning Assessment is being introduced as a coordination tool for communication to the RC in R3, and coordination actions pursuant to the Assessment are specified in R4. Given that the RC operates in the Operations Planning and Real-Time environment, yet the Planning Assessment is a long term planning instrument, we do not believe that this coordination is applicable or useful. Rather, the RC should

Organization	Yes or No	Question 6 Comment
		be seeking next-day assessments from the TOP entities within its footprint. Suggest removal of these requirements.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. However, changes were made to Requirement R4 as noted in the summary comments, to further clarify the intent of this requirement.		
Peak Reliability	Yes	o R1.3: "Reliability Coordinator Wide Area" should be "Reliability Coordinator's Wide Area"
Response: The SDT agrees and has changed the requirement to "its Wide Area" for clarity. See summary consideration for revisions.		
ReliabilityFirst	Yes	ReliabilityFirst submits the following comments for consideration: 1. Requirement R4 - The term "coordinate" is ambiguous and unclear and may lead to unintended compliance implications. For example, is coordination satisfied by notice? RF recommends replacing the term "coordinate" with "jointly develop" in order to avoid unintended confusion.
Response: The SDT agrees and has made the suggested change. See summary consideration for revisions.		
Idaho Power	Yes	I don't have any great concerns with IRO-017-1 but R1 seems a little vague. Depending on the process that the RC establishes this could become quite onerous, it would be better if more of the outage coordination process was defined in the standard itself rather than leaving it entirely up to the RC.
Response: The SDT's intention was to permit a variety of coordination processes to better fit the individual needs of different Reliability Coordinators. No change made.		
Texas Reliability Entity	Yes	1) R 1.3: "Reliability Coordinator Wide Area" is not a defined term. Recommend removing the word "Wide" and use the defined term of Reliability Coordinator Area.

Organization	Yes or No	Question 6 Comment
Response: The SDT has clarified Requirement R1.3 to "its Wide Area". Please refer to the summary of changes.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
MRO NERC Standards Review Forum	Yes	
Colorado Springs Utilities	Yes	No Comments
SERC OC Review Group	Yes	
PPL NERC Registered Affiliates	Yes	
Rayburn Country Electric Cooperative	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Manitoba Hydro	Yes	
Exelon Companies	Yes	

Organization	Yes or No	Question 6 Comment
Xcel Energy	Yes	
PNMR	Yes	
David Kiguel	Yes	
PJM Interconnection	Yes	
Ameren	Yes	
Consumers Energy	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Response: Thank you for your response.		

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

Summary Consideration: There were a great deal of comments on proposed TOP-001-3 the majority of which were seeking clarifications, consistency, or relatively slight changes to requirements to make them more equitable. The SDT has responded to all comments and has made the following changes due to industry comments:

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.)

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

R1. Each Transmission Operator shall act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Transmission Operator Area.

R2. Each Balancing Authority shall act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Balancing Authority Area.

R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by its Transmission Operator

M4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity 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, Distribution Provider, or Load-Serving Entity may provide an attestation.

M5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity 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, Distribution Provider, or Load-Serving Entity may provide an attestation.

M6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity 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, Distribution Provider, or Load-Serving Entity may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators, 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.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known other 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 Emergency has occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, 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 NERC registered entities of outages of telemetering and telecommunication equipment, 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 monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to identify any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

M12. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding 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.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Data retention: Each Transmission Operator shall each keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and Real-time Assessment capabilities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and analysis capabilities.

R18. Each Transmission Operator and Balancing Authority shall always operate to the most limiting parameter in instances where there is a difference in SOLs.

Data retention: Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R11, and R14 through R20 and Measure M1 through M11, and M14 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	Requirement R5 has a zero-defect problem similar to what was argued for COM-002-4. A single instance of a failure to comply with any Operating Instruction results in a severe violation. We recommend a revision to this approach more consistent with the COM-002-4 penalties. A demonstrated pattern of problems would trigger a Severe VSL, but isolated single events, which did not impact the BES, should not be penalized. (It is hard to argue that not following an OI when one can during an Emergency would not be a severe VSL. Graduated levels could be similar to COM-002-4 R5.) FERC has stated that VSLs should be graded. These are not. Further, intent to perform should count in favor of any entity that is unable to implement an Operating Instruction due to a technical or reliability related concerns. (It is hard to argue that not following an OI when one can during an Emergency would not be Severe. Graduated levels could be similar to COM-002-4 R5.) Regarding Requirement R13, TOPs perform Real-time Reliability Assessments using their EMS Contingency Analysis systems and it is reasonable to expect that such systems would generate results at least every 30 minutes. However, a failure of the EMS or SCADA or of the contingency analysis software should not automatically result in a severe violation. For example, EOP-008-1 R1 allows a TOP two hours following the loss of primary control center functionality to re-establish situational awareness, yet such an event would automatically result in a severe violation of this requirement. We suggest revising R13 to read: Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes when the EMS and SCADA are functional. There is no way to perform a Real - time Assessment without EMS and SCADA given the new definition. In Measure M4, change Generation Operation to Generator Operator. In Measure M5, suggest changing "...Operating Instruction issued by the Transmission Operator(s)" to "...Operating Instructions issued by the Balancing Authority” to match the language in R5.

Organization	Yes or No	Question 7 Comment
		In Measure M6, suggest changing "Balancing Authority" to "Transmission Operator" in the last sentence of the paragraph "If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation." to match the language in R6. Regarding Measure M8, no evidence is needed to show that the Transmission Operator informed the impacted Balancing Authorities. If so, why are they included in R8? Throughout the standard we find "an SOL". In the IRO standards we see "a SOL". Should be “a SOL”. To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes. Requirements R1 and R2 appear to create a double jeopardy situation as the TOP is already obligated to comply with all the other requirements for which it is the functional entity. To do so might necessitate issuing Operating Instructions to direct others to act. For example: A TOP needs to issue an Operating Instruction to shed load to comply with EOP. If the TOP does not issue the OI then it won’t comply with its EOP load shed plan. That is a failure to shed load and failure to issue the OI. It is important to clarify R7 by retaining the concept of comparability of actions. For example, the requested TOP or BA should not be expected to implement load shedding if the requesting TOP hasn’t exhausted that option. Suggest changing emergency procedures to comparable emergency procedures. In R8 we agree the TO should inform impacted entities of operations that result in an emergency. However, including operations that “could result in an emergency” is far too broad and might potentially result in limitless notifications. R9 has several issues that need to be addressed. The SDT is utilizing the word negative to limit the need to make notifications, but it is introducing ambiguities in the meaning and determination of negative impact that could result in an unbounded

Organization	Yes or No	Question 7 Comment
		requirement to make notifications. We suggest introducing additional phrases to define negative. Negative impact should mean to reduce the ability to perform an entity's reliability function. The Measure states this is limited to planned outages while the requirement does not use the word planned. This needs to be resolved. The requirement to coordinate outages would conflict with and cause double jeopardy with the existing COM-001 R3 requirement to coordinate telecom systems within and between areas, including investigating and recommending solutions to problems. It also conflicts with proposed COM-001-2 R10 to within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. The Southwest Outage Report was specific about loss of RTCA. As written the requirement could be interpreted to mean recording loss of a control point or analog value and whether it impacted another NERC entity, and evidence of notification. Consider revising R9 to read: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and those interconnected NERC registered entities that utilize the outages equipment in the performance of their reliability functions of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. A different approach would be to split the requirements into a BA and a TOP limited Requirement. The BA would remain the same as the suggested rephrasing above and the TOP would state: Each Transmission Operator shall notify its Reliability Coordinator and those interconnected NERC registered entities that are within the TOP Area that the TOP Real-time Contingency Analysis tools are not functioning properly and reduces the ability of the TOP to monitor its area. Regarding R10, if a sub-100 kV facility is needed to maintain reliability, it should be included in the BES by exception. This standard should require the TOP to monitor

Organization	Yes or No	Question 7 Comment
		BES Elements in its area. Monitoring BES Elements beyond that is the responsibility of the RC. Monitoring of neighboring facilities presents an authority issue, which is clearly defined in the IERP Report, and Paragraphs 84 and 87 of the NOPR. R10 as written implies the TOP needs to monitor its neighboring TOP's entire area when in reality a subset of facilities may be all that is required. One suggestion rephrasing is Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and those Facilities it determines as necessary in its neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area... Another suggestion is: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area. Requirement R16 could be clarified by using the wording in IRO-002-2 R8, which is the same requirement for the RC. Requirement R17 could be clarified by using the wording in IRO-002-2 R8, which is the same requirement for the RC. Requirement R16 and R17--System Operators should have authority to both approve and disapprove planned outages and maintenance of its monitoring and Real-time assessment (analysis) capabilities. "...maintenance of its monitoring and analysis capabilities." What is "its" referring to? The Rationale isn't clear on this either.

Response: Please see response to q14.

The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability.

Organization	Yes or No	Question 7 Comment

The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.

The SDT has deleted 'telecommunications' from the requirement as it is already covered in proposed COM-001-2 Requirement R3. See summary consideration for revision.

The SDT agrees with changing Generation Operator to Generator Operator in Measure M4. See summary consideration for revision.

The SDT agrees with changing Transmission Operator to Balancing Authority in Measure M5. See summary consideration for revision.

The SDT agrees with changing Balancing Authority to Transmission Operator in Measure M6. See summary consideration for revision.

The SDT modified Measure M8 to include Balancing Authority in the measure. See summary consideration for revision.

The SDT agrees that "an SOL" is grammatically incorrect and has changed to "a SOL" throughout the standards.

Organization	Yes or No	Question 7 Comment

Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure.

The requirement already includes the requesting entity to have "implemented its emergency procedures". Thus, the "concept of comparability of actions" is already included. No change made.

The SDT disagrees that "including operations that 'could result in an emergency' is far too broad". The Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators need to be aware of the threats to the reliability of the Bulk Electric System including potential threats. The SDT does not believe that this will result in "limitless notifications". No change made.

The SDT agrees that using "negative" in Requirement R9 creates ambiguity. Requirement R9 has been modified to remove the term "negative" as well as to accommodate other changes suggested by industry. See summary consideration for revision.

The SDT agrees that Requirement R9 and Measure M9 need to be consistent with regard to inclusion of all telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. Measure M9 has been modified to remove the word "planned". See summary consideration for revision.

The SDT disagrees that Requirement R9 conflicts with COM-001.1 Requirement R3. Requirement R9 does not require coordination but rather only notification. Furthermore, proposed COM-001-2 has been approved by the NERC Board and is pending regulatory approval before the Commission. Thus, approved COM-001.1 Requirement R3 is expected to be retired. The SDT has made clarifying changes to Requirement R9 based on comments received. See summary consideration for revision.

While the SDT recognizes that Requirement R9 may be liberally interpreted as applying to a single control point that was not the intent of the requirement and believes a reasonable reading of the requirement would be that it applies to only the equipment that impacts other entities. Thus, most control points or analog values will not have an impact and will not be covered. However, there may be certain important control points or analog values (e.g., IROL flow or tie-line flow) that do impact and are covered. The proposed changes are more confusing and ambiguous. Furthermore, the SDT disagrees with splitting the requirement into Transmission Operator and Balancing Authority requirements as proposed. The purpose of the requirement is not just for the Transmission Operator to notify other entities when its RTCA is not functioning but to notify other entities of outages such as telemetry outages that could affect their monitoring tools. The SDT has made clarifying changes to Requirement R9 based on comments. See summary consideration for revision.

Organization	Yes or No	Question 7 Comment
For Requirement R10, the SDT agrees that if a sub-100 kV facility is needed to maintain reliability that it should be included in the BES by exception. Thus, the SDT has modified the requirement accordingly. The SDT agrees that the requirement could imply the need for a Transmission Operator to monitor all of its neighboring Transmission Operators Facilities and that the Transmission Operator only needs to monitor its neighbor's Facilities that would impact its reliability. The requirement has been modified accordingly. See summary consideration for revision. The SDT agrees and has changed proposed TOP-001-3, Requirements R16 and R17 to match proposed IRO-002-2, Requirement R3. See summary consideration for revision. The SDT disagrees. Authority to approve provides de facto authority to not approve. No change made. "its" is used to imply ownership. In other words, the responsible entity is responsible only for "monitoring and analysis" capabilities that it owns. The SDT believes this is clear but has removed "own" to reduce redundancy in the language. See summary consideration for revision.		
Associated Electric Cooperative, Inc. - JRO00088	No	FOR: TOP-001-3, draft 1 clean, general COMMENT: AECI supports comments posted by the SERC OC Work Group. FOR: TOP-001-3 draft 1 clean - All Measures, including this SDT's other posted draft Standards for Comment: This Standard, along with all others revised by this project's Drafting Team, appears to word the Measures as Requirements. AECI believes the following examples represents changes that would be more conformant with other NERC Standard revisions: REPLACE: "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, or directed others to act by issuing Operating Instructions to address its reliability functions within its Transmission Operator Area." WITH: "M1. Examples of evidence 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 may be used to determine that it acted, or directed others to act by issuing Operating Instructions to address its reliability functions within its Transmission Operator Area."

Organization	Yes or No	Question 7 Comment
		FOR: TOP-001-3 draft 1 clean, all references to Load-Serving Entity REMOVE: "Load-Serving Entity" from: Applicability Section 4.5, Requirement R3 and Measurement M3, Requirement R4 and Measurement M4, Requirement R5 and Measurement M5, Requirement R6 and Measurement M6. RATIONALE: See NERC Website, Program Areas & Departments, Compliance & Enforcement, Compliance Analysis and Certification, Risk-Based Registration Initiative, "RBR Design 20140602 FINAL", "Appendix A - Risk-Based Registration Threshold Reviews", pages A-3 thru A-6, Section "Load-Serving Entity", on recommendations for removal based upon lack of Reliability Related Functions performed. FOR: TOP-001-3 draft1 clean, definition for Reliability Directive REPLACE: Rationale for definition for Reliability Directive being dropped WITH: Earlier definition for Reliability directive RATIONALE: AECI strongly advises this SDT and all of Industry, to reconsider this current draft's implication that all Operating Instructions are of equal weight, pertaining to options for discussion, where equally or more effective solutions could and should be made available for discussion by the issuer. This current draft's language does not allow options for reconsideration, when FERC itself often cites possible solutions by closing with "or an equally effective and efficient solution". We earnestly plead with the SDT to carefully reconsider all instances where their wording choices currently bind the recipients of any Operating Instruction with absolutely no choice beyond blind complicity in all instances where the Instruction is physically feasible, safe, and legal. AECI believes such language, executed literally, unnecessarily exposes Responsible Entities to extreme financial burden, with rare benefit to BES Reliability. This is true where equally reliable yet more cost-effective solutions in fact existed, yet could not be proposed without the Operating Instruction's recipient risking violation in several of these drafted Requirements. Please note that AECI does agree that there could be times where the Issuer, particularly RCs in light of rapidly deteriorating BES Conditions, need the authority to issue some Operating Instructions that allow no discussion beyond these conditions currently cited. Yet we firmly believe the vast majority of Operating

Organization	Yes or No	Question 7 Comment
		Instructions should not carry this currently-drafted weight of no recourse upon the issuer or recipient. FOR: TOP-001-3 draft 1 clean, definition of Real-time Assessment COMMENT: AECI strongly favors the parenthetical sentence that appears as the last sentence within this definition, and believe it can help smaller Responsible Entities to avoid unnecessary cost of compliance where Real-time Assessments are required. COMMENT: We recommend the Real-time Assessment and Operational Planning Analysis definitions include the following change: 'The assessment may reflect inputs including, but not limited to: load, generation output levels,...'RATIONALE: Inputs in the currently proposed definition are not applicable to all situations where assessments and analysis are needed. Usage of "may" provides recommendation for inputs that are valuable in some situations (and are currently used when applicable), however it does not require these inputs for every assessment, which creates an unneeded burden. FOR: TOP-001-3 draft 1 clean, Effective Date COMMENT: In requirements where Real-Time Assessment was not currently required, AECI believes newly-applicable entities should be provided with 36 months to become compliant, due to time necessary for smaller entities to research, budget, and enlist in third-party services, then sufficiently train their Operators to effectively utilize their new tool for reliability and compliance. FOR: TOP-001-3 draft 1 clean, Requirements R1 and R2CAUTION: These requirements appear to dictate that no action upon the BES will be issued in any manner outside the definition of an Operating Instruction. While AECI believes the underlying intent within this language is that all changes to the BES take place with recorded three-part communications, R3 in conjunction with R1 and R2, collectively imply dictatorial rule of every issuer over every recipient any time any BES element's state changes due to an Issuer's Operating Instruction.

Organization	Yes or No	Question 7 Comment
		FOR: TOP-001-3 draft 1 clean, Requirement R3 and R5 (absolute deal-breaker for AECI)REPLACE: "statutory requirements" WITH: "statutory requirements, or has no equally or more effective alternative" RATIONALE: For most routine Operating Instructions, both Issuers and Recipients of Operating Instructions should be provided the option to have equally or more effective solutions discussed prior an ultimate action being taken. FOR: TOP-001-3 draft 1 clean, Requirement R4PROPOSED INSERTION: a new R4, immediately following R3R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]RATIONALE: This new R4, essentially equivalent to R3 yet without the option to discuss equally or more effective actions, is provided where Reliability Directives (proposed for reinsertion) have been issued, as a unique class of Operating Instructions. (AECI understands that, even with our earlier R3 proposed change accepted, the SDT and Industry may not agree that this "no further discussion" Requirement is necessary under any circumstances. We only offer it as an optional companion of the R3 change above.) FOR: TOP-001-3 draft 1 clean, Requirement R4 (not our proposed R4 insertion) REPLACE: "reasons shown in Requirement R3."WITH: "reasons shown in Requirement R3, with exception of equally or more effective solutions." RATIONALE: AECI does not believe BES Reliability would be served by requiring that all equally or more effective solutions be discussed. FOR: TOP-001-3 draft 1 clean, Requirement R6PROPOSED INSERTION: a new R7 (this R7 numbering assumes a new R4 was similarly inserted) R7. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment,

Organization	Yes or No	Question 7 Comment
		regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]RATIONALE: This new R7, essentially equivalent to draft R5 yet without the option to discuss equally or more effective actions, is provided where Reliability Directives (proposed for reinsertion) have been issued, as a unique class of Operating Instructions. (AECI understands that, even with our earlier R5 proposed change accepted, the SDT and Industry may not agree that this “no further discussion” Requirement is necessary under any circumstances. We only offer it as an optional companion of the R5 change above.) FOR: TOP-001-3 draft 1 clean, Requirement R6 (original draft R6) REPLACE: “issued by that Balancing Authority.” WITH: “issued by that Balancing Authority citing one of the specific reasons shown in Requirement R5, with exception of equally or more effective solutions.” RATIONALE: Consistency with R4 AECI does not believe BES Reliability would be served by requiring that all equally or more effective solutions be discussed. FOR: TOP-001-3 draft 1 clean, Requirement R7 (deal-breaker for AECI)COMMENT: AECI fully agrees with this requirement’s preceding rationale, where insertion of “Effective’ was noted. However AECI does not agree with current R7 language that omits the referenced inclusion. As suggested earlier under R3 and R5, AECI strongly recommends that industry be afforded opportunity to raise equally or more effective solutions for discussion as part of requesting and lending assistance, over blind compliance for any requested action this is physically possible, safe and legal. FOR: TOP-001-3 draft 1 clean, Requirement R8 (deal-breaker for AECI)REPLACE: “impacted” WITH: “known impacted” RATIONALE: True extent of impact may not be obvious to a responsible entity at all times. FOR: TOP-001-3 draft 1 clean, Requirement R9 (deal-breaker for AECI)REPLACE: “outages” WITH: “planned outages” REPLACE: “negatively impacted” WITH: “known negatively impacted” RATIONALE: Consistency of this Requirement’s language with its corresponding measurement and VSL. Also, the extent of negative impact for data

Organization	Yes or No	Question 7 Comment
		absence is practically impossible to gauge, due to the current complexity of data being circulated upstream of an RC. Notification of your RC should be sufficient. FOR: TOP-001-3 draft 1 clean, Requirement R10 (deal-breaker for AECI)REPLACE: "Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area." WITH: "Each Transmission Operator shall monitor Facilities, within its Transmission Operator Area and neighboring Transmission Operator Areas - including sub-100 kV facilities and the status of Special Protection Systems, Functionally needed to maintain BES reliability." RATIONALE: Scope of NERC Requirements should remain pertinent to BES Reliability Functions. FOR: TOP-001-3 draft 1 clean, Requirement R11COMMENT: This requirement should eventually make its way into a BAL Standard REPLACE: "shall monitor its Balancing Authority Area, including the status of" WITH: "shall include the status of" RATIONALE: The BAL Standards already include an extensive set of requirements pertinent to the included measurements and their quality that is pertinent to performing their reliability function. Blanket inclusion of the same within this Requirement is redundant. Further, this requirement should really be handled in a different manner, perhaps as a rapid modification to an existing BAL requirement. FOR: TOP-001-3 draft 1 clean, Requirement R12REPLACE: "Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL Tv." WITH: Each Transmission Operator shall monitor the continuous duration of exceeded limits for all identified Interconnection Reliability Operating Limits (IROLs), and act to assure they are returned to normal before to any such duration exceeds their associated IROL Tv. RATIONALE: Rephrased requirement in a positive sense. FOR: TOP-001-3 draft 1 clean, Rationale for Requirement R14REPLACE: "such an Operating Plan" WITH: "such an Operating Plan, developed per requirements within

Organization	Yes or No	Question 7 Comment
		TOP-002"RATIONALE: This is the first occurrence of the term "Operating Plan" within the Requirements of this TOP Standard. While the current Rationale for Requirement R14 does reference this SDT's white paper, the reader is currently left wondering if this is a hidden requirement for development of Operating Plan(s), or whether the requirement actually exists elsewhere within the body of NERC Standards. FOR: TOP-001-3 draft 1 clean, Requirement R15REPLACE: "of its actions to" WITH: "of its actions taken to" RATIONALE: Clarity - to differentiate that this requirement is not a repeat, to inform the RC of action(s) developed within all Operating Plans, but rather the TOP's anticipated or actual action taken to mitigate the SOL exceedance that triggered their activation of that previously communicated Operating Plan.

Response: Please see response to SERC's comments.

While the measures may use similar words to the requirements such as "shall" and "provide", the SDT disagrees that this makes the measurements like requirements and believes the choice of words is ultimately irrelevant because measurements are simply not requirements. Measurements provide lists of types of evidence that may be useful proving compliance. Furthermore, these measures are consistent with the way other NERC standards measurements are written. No change made.

There are active discussions about the future role of the Load-Serving Entity but for the moment it is included in the Functional Model v5. The SDT is required to follow that document in its work. If the group looking into the deletion of Load-Serving Entity decides to eliminate it, it will be the responsibility of that group to come up with a plan to bring the body of standards up to date.

The SDT disagrees with replacing Operating Instruction with Reliability Directive and disagrees that issuance of an Operating Instruction requires "blind complicity in all instances". While it is true that Requirement R3 compels a responsible entity to comply with an Operating Instruction issued by a higher level authority, there is nothing in the requirements that says that the responsible entity cannot question the instruction after verifying through three-part communications. Even with this statement, the kind of operating structure that could arise if a lower operating authority is not required to follow the Operating Instructions of a higher level authority could cause chaos and negatively impact reliability by making following Operating Instructions optional. No change made.

Thank you for your support of the parenthetical in Real-time Assessment.

Organization	Yes or No	Question 7 Comment
The SDT disagrees with the use of “may” rather than “shall” in the definition of Real-time Assessment and Operational Planning Analysis. However, the SDT has made clarifying changes to the definitions based on comments. See summary consideration for revision. The SDT disagrees with the need to extend the implementation period to 36 months for Real-time Assessments. While they may not have been explicitly required, Real-time Assessments have always been necessary for a Transmission Operator. Transmission Operators are currently required to operate within all SOLs and IROLs. How can they do this today without performing a Real-time Assessment? No change made. The SDT agrees that every action that changes or preserves “the state, status, output, or input of an Element” will be covered under Requirements R1, R2, and R3 and does not see an issue with a lower operating authority being required to follow the instructions of a higher operating authority. If this were not the case, then instructions from a Transmission Operator to a Distribution Provider would be merely suggestions and reliability would be jeopardized by the operational chaos such an environment would create. No change made. The SDT disagrees with the need to make a change to Requirements R3 and R5 to allow the recipient of an Operating Instruction to implement an “equally or more effective alternative”. A higher level operating authority should be able to expect a lower level operational authority to follow its instructions. Hopefully, if there are multiple available solutions, the higher authority would discuss those with the lower authority before issuing them. AECI should work with its operational entities to ensure they have a relationship that allows such discussion before issuance of Operating Instructions. No change made. Because the change to Requirement R3 was not adopted, the SDT does not believe a new Requirement R4 is necessary to apply just to Reliability Directives. No change made. Since the change to Requirement R3 was not adopted, the proposed change to Requirement R4 is not necessary. No change made. Because the change to Requirement R5 was not adopted, the SDT does not believe a new Requirement R7 is necessary to apply just to Reliability Directives. No change made. Because the change to Requirement R5 was not adopted, the proposed change to Requirement R6 is not necessary. No change made. The SDT agrees that the language in the rationale box and Requirement R7 do not match. The rationale has been adjusted accordingly. The SDT has made other clarifying changes to the requirement based on comments. See summary consideration for revision.		

Organization	Yes or No	Question 7 Comment
The SDT agrees that the suggested change provides additional clarity and has made the change. See summary consideration for revision. The SDT has added 'known' to the requirement as suggested. However, the SDT disagrees that this requirement should only apply to planned outages. If a Balancing Authority's or Transmission Operator's ICCP connection experiences an unexpected outage, it absolutely should be required to notify the "known" impacted entities. See summary consideration for revision. The SDT has revised Requirement R10 to provide additional clarity due to your comment and those of others. See summary consideration for revision. For Requirement R11, the suggested modifications appear to be incomplete and would result in the Balancing Authority including SPS. It is not clear what they would be included in. The SDT agrees that this requirement should eventually be in the Balancing Authority standards but that is out of scope for this project and will have to be handled by a later project. No change made. The SDT does not believe that the suggested change provides additional clarity. No change made. The SDT agrees that Requirement R14 was not intended to require development of a new operating plan but implementation of pre-developed Operating Plans and will update the rationale. See summary consideration for revision. The SDT disagrees that adding "taken" to Requirement R15 provides any additional clarification. Actions would be "taken". No change made.		
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	Definition for Real-time Assessment: Delete the parenthetical. This does not clarify what the analysis is. At a minimum replace the word "contracted" with "arranged". R1 - This could place a huge burden for evidence control on the entities because Operating Instruction is altering the state of any BES Facility. This responsibility is inherent to the Functional Model and does not need to be a requirement. At a minimum, recommend removal of the Operations Planning horizon tasks and narrow down focus of intent. The term "Operating Instruction" is defined for Real-time operation. SDT should review the term Transmission Operator Area because it would not include LSE, DPs, etc. R2 - Please see comments for TOP-001-3 R1 above.

Organization	Yes or No	Question 7 Comment
		R3 - Operating Instruction is too broad of a definition that would require a huge amount of evidence. The defined term refers to too many circumstances and not only to "emergency conditions." At a minimum, this requirement should only refer to the Real-time Operations time horizon. We also recommend LSE and DPs be removed from this requirement. The LSE's cannot perform any corrective action. Refer to Functional Model for LSEs and DPs. In addition, there is a current proposal to remove LSEs from registry. R4 - Please see comments for TOP-001-3 R3 above. R5 - Please see comments for TOP-001-3 R3 above. R6 - Please see comments for TOP-001-3 R3 above. R7 - TOP-001-1a R6 stated "available emergency assistance" and the new requirement states "shall assist". Recommendation would be to change the language to "if requested and available." The RC will take the appropriate actions if there is a reliability related need. Assistance should be available to BAs as well, current wording is not symmetrical. R8 - The requirement is defining operations that could result in an Emergency and may be defining the term Emergency. The examples given are not necessarily considered an Emergency, unless they were "significant" changes and unplanned. Even then, the actions may still not constitute an Emergency. R9 - M9 refers to planned outages. If that was the intent, the word "planned" should be added to the requirement. SW Outage Report Recommendation 15 specifically addressed RTCA. This requirement was expanded beyond the recommendation. Does "monitoring and assessment capabilities" refer to Real-time Assessment capabilities? New proposed language is too broad. Recommendation would be to focus on loss of RTCA capabilities. R10 - To eliminate confusion, we recommend creating two requirements with the following language:" Each Transmission Operator shall monitor Facilities, and identified sub-100 kV facilities, within its Transmission Operator Area and

Organization	Yes or No	Question 7 Comment
		neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area." "Each Transmission Operator shall monitor the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area." The addition of Special Protection Systems to this requirement eliminates the need for SPSs within the new Real-time Assessment term definition. R13 - It is important for Real-time Assessments to be performed, however, it is not important who does them. Recommend language: "Each Transmission Operator shall ensure a Real-time Assessment is performed at least once every 30 minutes." This language allows other entities (including the RC as was the case in IRO-008-1 R2) to complete the assessment, but maintains the responsibility on the TOP as desired in the rational for R13. This falls in-line with the new definition for Real-time Assessment. R14 - The term "Real-time monitoring" is not a defined term. Existing and potential operating conditions are included in the Real-time Assessment defined term. As defined, the term "Operating Plan" refers to a formal document referencing a specific scenario or potential SOL exceedance. We have a concern on how the term Operating Plan is utilized throughout the proposed Standards and how they are linked to the OPA and RTA. We recommend changing the requirement to read: "Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified in its Real-time Assessment." R16 & R17 - We recommend the following language: "Each TOP and BA shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools."

Response: (1) The SDT disagrees with deleting the parenthetical from the definition of Real-time Assessment. Other commenters have found it beneficial because it does provide for additional explanation. The SDT agrees with clarifying "contracted". A

Organization	Yes or No	Question 7 Comment

corresponding change was made to the definition of Operational Planning Analysis for consistency. See summary consideration for revision.

The SDT disagrees that Requirement R1 is intended to apply only to Real-time and that the definition of Operating Instruction is limited to Real-time. The proposed definition of Operating Instruction is limited to those who can control actions in Real-time which would be the Reliability Coordinator, Transmission Operator, and Balancing Authority. It does not specify a time in which those actions can take place. Requirement R1 could also apply to an operational planning decision such as instructing an equipment owner to cancel an outage or it could apply to committing a generation unit with a long lead time such as two or three days. The SDT agrees the definition of Transmission Operator Area could be interpreted to exclude Load-Serving Entities and Distribution Providers and has modified Requirement R1 accordingly. The SDT does not believe that this requirement will place an undue burden on entities but has revised the data retention requirement for operator logs. The SDT also encourages the commenter to take an active role in the review of the RSAWs for this project. See summary consideration for revision.

The SDT disagrees that Requirement R2 is intended to apply only to Real-time. The proposed definition of Operating Instruction is limited to those who can control actions in Real-time which would be the Reliability Coordinator, Transmission Operator, and Balancing Authority. It does not specify a time in which those actions can take place. It could also apply to operational planning decision such as instructing an equipment owner to cancel an outage or it could apply to committing a generation unit with a long lead time such as two or three days. Furthermore, the SDT disagrees that the definition of Balancing Authority Area could be interpreted to exclude Load-Serving Entities and Distribution Providers. Unlike the Transmission Operator Area definition, the Balancing Authority Area definition explicitly includes Loads. The SDT does not believe that this requirement will place an undue burden on entities but has revised the data retention requirement for operator logs. The SDT also encourages the commenter to take an active role in the review of the RSAWs for this project. See summary consideration for revision.

The SDT disagrees that Requirement R3 is intended to apply only to Real-time. The proposed definition of Operating Instruction is limited to those who can control actions in Real-time which would be the Reliability Coordinator, Transmission Operator, and Balancing Authority. It does not specify a time in which those actions can take place. It could also apply to operational planning decision such as instructing an equipment owner to cancel an outage or it could apply to committing a generation unit with a long lead time such as two or three days. There are active discussions about the future role of the Load-Serving Entity but for the moment it is included in the Functional Model v5. The SDT is required to follow that document in its work. If the group looking into the deletion of Load-Serving Entity decides to eliminate it, it will be the responsibility of that group to come up with a plan to bring the body of standards up to date. Load-Serving Entities can perform corrective actions such as shedding Load. No change made.

Organization	Yes or No	Question 7 Comment
See comments for Requirement R3. See comments for Requirement R4. See comments for Requirement R5. See comments for Requirement R6. The SDT agrees with the suggestion to add “and available” to the requirement and that the requirement is not symmetrical and appropriate changes have been made. See summary consideration for revision. The SDT agrees and has deleted the examples. See summary consideration for revision. The SDT has modified Measure M9 to remove “planned” as the requirement applies to both planned and unplanned outages. The SDT disagrees that the requirement is too broad and that “monitoring and assessment capabilities” would only apply to RTCA capabilities. It could also apply to SCADA or alarming as an example. See summary consideration for revision. The SDT disagrees that Requirement R10 should be split into two requirements. However, the SDT has modified the requirement for additional clarity in response to this and other comments. The SDT also disagrees that that the addition of SPS to this requirement obviates the need for SPS in the Real-time Assessment definition. This requirement is to monitor the status of an SPS and may trigger the need to perform a Real-time Assessment if an SPS were suddenly unavailable. The subsequent Real-time Assessment then should reflect that the SPS is no longer available. See summary consideration for revision. The SDT has revised the requirement language for clarification. See summary consideration for revision. The SDT disagrees. Real-time monitoring can produce alarms that would precipitate action. No change made. The SDT believe the proposed changes to R16 and 17are largely unnecessary, do not provide additional clarity and actually remove the true reliability intent of the requirement. The true reliability intent is that the System Operator has authority over his tools. The proposed changes removed System Operator. Furthermore, approval authority would grant authority to approve, deny or cancel planned outages. Monitoring and Real-time Assessment capabilities could include hardware, analysis tools and the EMS. However, it may not include telecommunication so the SDT is adding telecommunication to the requirements. See summary consideration for revision.		
MRO NERC Standards Review Forum	No	Comments: In R1 and R2, the wording of “reliability function” is used and the NSRF suggest replacing it with “to maintain system stability”. This is more in line with the definition of an Operating Instruction. If “reliability function” is maintained, we

Organization	Yes or No	Question 7 Comment
		believe that any conversation or discussions concerning what the entity's function is, would be construed as an Operating Instruction. We believe this is not the intent of the SDT. R4 is predicated on R3 and only allows entities the inability to perform the issued Operating Instruction based on "unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements". The entity then must cite which specific reason why they cannot perform the Operating Instruction. The NSRF does not agree with this due to the limited possibilities for not performing the Operating Instruction. The NSRF recommends deleting "citing one of the specific reasons shown in Requirement R3", as this wording does not prevent instability, uncontrolled separations or Cascading outages. We do not need rules this specific, the issuing entity can always ask why the receiving entity cannot perform the Operating Instruction. During a real time event, the TOP only cares about the mitigating actions that they have available in order to maintain system stability. If a requested action cannot be accomplished by the requested entity, the TOP will quickly move to their next mitigating action. There is no need for small talk of "why" the requested action cannot be performed. The NSRF believes this was a partial cause of the 2003 blackout. R8. The NSRF understands the intent of R8 and recommends the words "system or equipment" be added prior to operations. Recommended changes provide clarity as, "...of its actual or expected system or equipment operations that result in...". This provides clarity to what type of operations the Requirements is referring to. R8. Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected system or equipment operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load. R9 - Notification of telemetering and telecommunication outages. The SW Outage Report recommendation is specific to reporting technical issues with their

Organization	Yes or No	Question 7 Comment
		contingency analysis capabilities after the functionality is lost. Therefore, the requirement should be revised to only address forced or unexpected outages. Recommend that R9 read as: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and (removed negatively) potentially impacted interconnected NERC registered entities of forced outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities R13 - Perform Real-time Assessment at least once every 30 minutes. Paragraphs 55 and 60 (of the NOPR) do not specifically require a timeframe for monitoring and assessment capabilities. Therefore it is recommended to remove the Real-time Assessment at least once every 30 minute requirement. In addition, NERC has already developed the ERO Event Analysis Process Document to address reporting the loss of monitoring or control at control centers (which includes unacceptable State Estimator or Contingency Analysis solutions) and should provide adequate assurance of industry performance related to control center situational awareness tools. If the SDT retains the requirement, the NSRF recommends developing a performance based requirement as opposed to a single time limit in which the Transmission Operator would be required to report for every excursion. Example - CPS1 / CPS2 BA performance metrics.

Response: (1) The SDT has revised the requirement to add clarity and consistency with the IRO standards. See summary consideration for revision.

The SDT agrees in that in Real-time operations the Transmission Operator primarily only needs to know that an action could not be implemented. Why is less important. This makes the requirement consistent with Requirement R6. The requirement has been modified accordingly. See summary consideration for revision.

The SDT does not believe that the suggested change adds any additional clarity. No change made.

While the SDT understands that there were significant issues identified in the Southwest Outage Report regarding the failure of Contingency analysis, the SDT believes the issue is much broader than just forced outages and Contingency analysis. An outage of SCADA could have just as big an impact for example. Whether the outage is planned or forced is also not relevant because either

Organization	Yes or No	Question 7 Comment
type of outage is loss of capability that could impact operations. The requirement does not compel RTCA and there is no existing requirement to have RTCA. It is necessary to communicate the outage of key tools and monitoring capabilities. No change made. The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.		
Colorado Springs Utilities	No	1. R7 - "Effective" is not included in the requirement language as indicated in the rationale.

Organization	Yes or No	Question 7 Comment
		2. R13 needs additional time for implementation. Recommendation for 3 years from approval. We voted negative on this standard because we think that the implementation period needs to be longer. 3. R14 - There is currently no requirement to have a plan, so how can entities be required to follow a plan they are not required to create? Is a generic SOL mitigation plan satisfactory?
Response: 1. The SDT has revised the language based on your and other comments. See summary consideration for revision. 2. The SDT disagrees with the need to extend the implementation period to 36 months for Real-time Assessments. While they may not have been explicitly required, Real-time Assessments have always been necessary for a Transmission Operator. Transmission Operators are currently required to operate within all SOLs and IROLs. How can they do this without today performing a Real-time Assessment? No change made. 3. The SDT agrees that Requirement R14 was not intended to require development of a new Operating Plan but implementation of pre-developed Operating Plans and will update the rationale to explain this. Some minor modifications to the requirement have also been made for clarity. See summary consideration for revision.		
SERC OC Review Group	No	1) Request clarification on who “others” are for R1 & R2, “RC shall act, or direct others to act,”. Suggestion: “directs others (as identified in R3) to act”. Current: “shall act, or direct others...” Suggested: “shall act, or direct others (as identified in R3)...” 2) R7 is missing the use of the word “effective” that was referenced in the rationale. 3) In R9, remove “and negatively impacted interconnected NERC registered entities” because each entity does not always know who may be impacted. (i.e., entity in SERC is providing data to NYISO. Is NYISO an impacted entity for loss of the data?) Also, insert ‘planned’ before outages in Requirement to be consistent with M9 and the VSL for R9.Current: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment,

Organization	Yes or No	Question 7 Comment
		control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities." Suggested: "Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator of planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities." 4) In the R13 VSLs, there is concern that the bandwidth between "lower" and "severe" VSL is only 15 minutes. Suggestion: expand bandwidth. See also response on IRO-008-2, question 3 above.
Response: 1) The SDT does not believe that "others" in Requirements R1 and R2 requires any further clarification. The commenters seem to correctly understand that Requirements R3 and R5 are complimentary and define who has to respond to the Transmission Operator and Balancing Authority in Requirements R1 and R2. No change made. 2) The SDT agrees that the language in the rationale box and Requirement R7 do not match. The rationale has been adjusted accordingly. The SDT has made other clarifying changes to the requirement based on comments. See summary consideration for revision. 3) The SDT disagrees and believes that the Transmission Operator is in a position to know which outages of its telecommunications, control equipment, and monitoring and assessment capabilities will impact other entities. It should be limited to those areas that are impacted by the loss of their transmission, generation, or Load within its Transmission Operator Area. No change made. 4) See response to Q14.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	No	R1 and R2 - Southern suggest that Requirements 1 and 2 are high level and generic and that the requirements do not seem results-based. R7 - The Rationale section for Requirement R7 states that the word 'Emergency' was deleted and the word 'Effective' was added to the Requirement language. The word 'Effective' is missing from the Requirement language. R8 - Southern suggests that the phrase 'could result in' is too open ended and assumes that operations takes place as expected and does not account for failures

Organization	Yes or No	Question 7 Comment
Generation and Energy Marketing		and equipment during the operations such as faulted breaker, or human performance errors. R9 - Add the word 'planned' to Requirement language to match Measure language. R9 - The phrase 'negatively impacted Interconnected NERC registered entities' seems broadly generic. Southern suggests adding the words, 'other affected adjacent BAs and TOPs'. Suggested Requirement language: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and other affected adjacent BAs and TOPs, of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Suggested Measure language:M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and other affected adjacent BAs and TOPs, of planned outages of telemetering and telecommunication equipment, 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 - Southern recommends adding the words 'as deemed necessary by the TOP' after the words sub-100 kV facilities which would make this TOP requirement consistent with the corresponding RC Requirement in IRO-008. Suggested Requirement language: R10. Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities, as deemed necessary by the TOP, to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area.

Organization	Yes or No	Question 7 Comment
		Suggested Measure language: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 monitors Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities as deemed necessary by the TOP, to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area . R11 - Southern suggests that the SDT coordinate with the SPS drafting team on the use of RAS versus SPS for Requirement R11 as well as throughout the standards included in this project. R14 - Southern suggest deleting the phrase, 'as part of', and adding 'as a result of'....Suggested Requirement language: R14. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as a result of its Real-time monitoring or Real-time Assessment. Suggested Measure language: M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as a result of its Real-time monitoring or Real-time Assessments. This evidence could include, but is not limited to, dated computer logs showing time the Operating Plan was initiated, dated checklists, or other evidence. R15 -Southern suggest that R15 as written has the potential for adding to Reliability Risk as it could cause the operator to spend time notifying the RC for compliance reasons rather than responding to the SOL exceedance. Instead, we suggest the requirement be re-written to have the TOP inform its RC of its inability to return the system to within limits when an SOL has been exceeded. Suggested Requirement language: R15. Each Transmission Operator shall inform its Reliability Coordinator of its inability to return the system to within limits when an SOL has been exceeded.

Organization	Yes or No	Question 7 Comment
		Suggested Measure language: M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of its inability to return the system to within limits when an SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recording, or dated computer printouts. R16 and R17 - These requirements only address planned outages of monitoring and assessment capabilities while the corresponding RC requirement in the IRO standards address maintenance of such capabilities as well. The SDT should review for consistency purposes. R16 and R17 - These requirements state that the TOP and BA shall provide its System Operators with the authority to approve planned outages of its own monitoring and analysis capabilities. Is clarification needed to reflect that the RC can override the authority given to System Operators as stated in R1 of EOP-002-2.1 (The RC has the ultimate responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and responsibility and shall exercise specific authority to alleviate capacity and energy emergencies.) R18 - There is confusion in the Industry of what the current term ‘derived limits’ means. The SDT should take this opportunity to clarify whether ‘derived limits’ is referring to SOLs, IROLs. If this is the case, then why use the term, ‘derived limits’?

Response: R1 and R2 – The SDT is attempting to create results-based standards. Without specific feedback, the SDT is unable to respond further.

The SDT agrees that the language in the rationale box and Requirement R7 do not match. The rationale has been adjusted accordingly. The SDT has made other clarifying changes to the requirement based on comments. See summary consideration for revision.

R8 - The SDT believes that the phrase is question is needed for reliability. If an entity has reason to believe that it has a potential condition that could result in an Emergency, it should inform the Reliability Coordinator and other potentially impacted entities in the interest of reliability. No change made.

Organization	Yes or No	Question 7 Comment
R9 - The SDT disagrees that this requirement should only apply to planned outages. If a Balancing Authority or Transmission Operators ICCP connection experiences an unexpected outage, it should be required to notify the other impacted entities. The SDT has deleted 'planned' from the Measure. See summary consideration for revision. R9 – The SDT agrees and has changed the requirement accordingly. See summary consideration for revision. R10 - The SDT agrees that the language of the requirement could be made clearer and has modified the language to show that the Transmission Operator identifies a subset of neighboring Transmission Operator facilities that should be monitored. See summary consideration for revision. R11 – The cited change has not been approved. If, and when, it is approved, that SDT will need to revise all standards and requirements accordingly. Until such time as the change is approved, the 2014-03 SDT must continue to use approved terms. No change made. R14 - The SDT has modified Requirement R14 for clarity based on comments of other standard. See summary consideration for revision. R15 – The SDT disagrees that Requirement R15 has the potential to cause the operating entity to notify the Reliability Coordinator for compliance reasons other than an SOL exceedance. The language is clear that the Transmission Operator shall notify the Reliability Coordinator "of its action to return the system to within limits when an **SOL was exceeded**" (emphasis added). This is past tense. Notification is not required until after the exceedance has occurred. No change made. R16 and R17 - The SDT agrees that the parallel requirements in proposed IRO-002-4 Requirement R3 and proposed TOP-001-3 Requirements R16 and R17 should be consistent and have made appropriate changes. See summary consideration for revision. R16 and R17 - The SDT does not believe that additional clarification to is needed to indicate that the Reliability Coordinator has authority over the Transmission Operator and Balancing Authority and can override its decision to approve outages of its monitoring and analysis capabilities. The Reliability Coordinator already has the authority to issue Operating Instructions to these entities of needed. No change made. R18 - The SDT agrees that derived limits can be made more specific and has modified the language of the requirement. See summary consideration for revision.		
Dominion	No	While Dominion agrees conceptually with Requirements 5 and 6 we do not believe they belong in the TOP family of standards.

Organization	Yes or No	Question 7 Comment
		Dominion does not agree with Requirement 7 as we do not see how it is substantially different from R3 and R5 under this standard and we expect that, in many cases, such assistance is likely to come in the form or an Operating Instruction issued by a Reliability Coordinator, in which case the recipient must comply. We oppose because this requirement does nothing to increase reliability; it only increases compliance risk for the entity. Dominion does not agree with R10 as written. We are opposed to the inclusion of the phrase "including sub-100 kV facilities". We could support if revised as indicated "Each Transmission Operator shall monitor BES Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area and the status of Special Protection Systems within its Transmission Operator Area." It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. Dominion has concerns with inclusion of Generator Operator in Requirement 18. The only limits the GOP is aware of are those for the facility it operates. The GOP is not typically provided limits or ratings for facilities it does not operate and, where it is provided such, it has only that single value and therefore no derived difference can be determined. For these reasons, we suggest Generator Operator be deleted from this requirement.
Response: The SDT ultimately agrees that Requirements R5 and R6 belong in the BAL standards but there is no current active project with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made. Requirement R7 differs from Requirement R3 in that Requirement R3 does not allow a Transmission Operator to Transmission Operator Operating Instruction. Requirement R5 is not relevant since it involves following a Balancing Authority's Operating Instructions and Requirement R7 involves assisting a Transmission Operator so they are initiated by two different entity types. The SDT agrees that Requirement R7 could be viewed as partially redundant with Requirement R3 for a Balancing Authority complying with a Transmission Operator issued Operating Instruction and will remove the Balancing Authority from the requirement. The SDT		

Organization	Yes or No	Question 7 Comment
has made modifications to this requirement based on other comments as well. See summary consideration for revision. The SDT also refers the commenter to approved EOP-001-2.1 and to on-going work in Project 2009-03. The SDT has revised Requirement R10 based on comments received. See summary consideration for revision. R18 - The SDT has modified the requirement to reflect that derived limits are SOLs. The SDT agrees that the Generator Operator should not be included for the purpose of SOLs because they will have no knowledge of these limits. Furthermore, the Transmission Operator and Reliability Coordinator could simply direct the Generator Operator to adjust unit outputs to operate within established SOLs. See summary consideration for revision.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services). Also, GOPs do not need to be listed in R18 since their role in operating to the most limiting parameter is to follow the directives of the TOP and BA.
Response: See response to FRCC comments. The SDT has modified the requirement to reflect that derived limits are SOLs. The SDT agrees that the Generator Operator should not be included for the purpose of SOLs because they will have no knowledge of these limits. Furthermore, the Transmission Operator and Reliability Coordinator could simply direct the Generator Operator to adjust unit outputs to operate within established SOLs, IROLs, and Facility Ratings. See summary consideration for revision.		
Duke Energy	No	Duke Energy does not agree with the proposed changes for TOP-001-3. Specifically, we have concerns that R1 and R2 as written do not appear to be Results-Based as laid out in the Rules of Procedure. The requirement that the TOP/BA "act" to ensure the reliability of the its area is not only a requirement that the entity do its job for which other requirements are applicable, but also a requirement that could be interpreted to require that the TOP/BA "act" to cover the full scope of any related reliability tasks listed under the NERC Functional Model. We believe such language should be removed and that the requirements should focus strictly on the communication desired when needed to ensure the reliability of the TOP or BA area.

Organization	Yes or No	Question 7 Comment
		R1: The TOP is already required to act in other applicable standards. We believe the requirement should continue to be bound to the defined scope of a Reliability Directive. R2: We disagree with the placing of the Balancing Authority here in this standard. We feel this is better placed within the BAL standard family. We believe the requirement should continue to be bound to the defined scope of a Reliability Directive. R3: The definition of Operating Instruction makes this requirement (and standard as a whole), too broad in nature. The definition of Operating Instruction carries past the parameters of action in an Emergency situation, and includes all actions. To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written. R4: No Comment R5: See Comment on R3 R6: See Comment on R3 R7: See Comment on R3 R8: Duke Energy suggests removing the reference to the examples and suggests the following: ”Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.” We believe the examples are not necessary in this requirement. R9: Duke Energy suggest the following revision: ”Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected Applicable entities of planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” We believe that “negatively impacted” is ambiguous and lacks clarity and suggest removing “negatively”. In addition, we believe using “Applicable entity” is a more

Organization	Yes or No	Question 7 Comment
		appropriate term to use than NERC registered entities. Finally, we suggest adding "planned outages" in order to be consistent with Measure 9. R10: Duke Energy believes that this requirement should be separated into two different requirements and suggests the following language: "Each Transmission Operator shall monitor Facilities, and identified sub-100 kV facilities, within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area. Each Transmission Operator shall monitor the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area." We believe separating this into two requirements will provide better clarity on the expectations that should be monitored by a TOP. R11: We believe that this requirement is better suited in the BAL family of standards. R12: No comments R13: While Duke Energy agrees, in general, that a Reliability Assessment shall be performed at least once every 30 minutes, we have concerns with this zero tolerance requirement. We believe a provision that allows for a defense in depth strategy is needed to allow the TOP to develop a plan, process, or procedure for those instance where various tool(s) used to conduct the Reliability Assessment are unavailable for longer than 30 minutes. This would align with NERC's transition to the RAI Initiative. In addition, EOP-008-1 R1.5 allows a transition period of less than or equal to 2 hours for a TOP to transition to its backup control center. If a TOP is in its transition phase and it takes longer than 30 minutes to become fully implemented, would the TOP violate R13 of this requirement? It could take longer than 30 minutes for an entity to arrive at the backup control center for various reasons. This is one of the reasons why a defense in depth strategy is needed in this requirement. R14: Duke Energy suggests removing "Real-time monitoring" from this requirement.

Organization	Yes or No	Question 7 Comment
		R15: No comments R16/R17: - Duke Energy suggests combining the two requirements and rewording as follows: "Each TOP and BA shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools." The removal of System Operators is necessary in the context of this requirement. Per the NERC definition, System Operators are the individuals "who operates or directs the operation of the Bulk Electric System (BES) in Real-time." System Operators work in a real-time environment and thus is in direct conflict with the use of the Operations Planning Time Horizon (next day to seasonal) in this requirement. In addition, we believe the TOP and BA should have the authority to approve, deny or cancel these types of outages in R3, not just the individual System Operators. There can be instances where a program tool used to perform a next-day study analysis could be requested to be taken out of service for maintenance and the TOP and BA needs to have the authority to deny that request. R18: No comments
Response: (1) The SDT has attempted to create results-based standards. In response to other comments, the SDT did modify Requirements R1 and R2 to reflect that the true requirement is to act to maintain reliability not "to address its reliability functions". Furthermore, the "communication desired when needed to ensure the reliability of the Transmission Operator or Balancing Authority area" will be covered under proposed COM-002-4. See summary consideration for revision. (2) The SDT disagrees that the requirement to act in Requirement R1 is already covered in other Reliability Standards and without a specific reference do not see justification for modifying Requirement R1. No change made. (3) The SDT ultimately agrees that Requirements R2, R5, R6, and R11 belong in the BAL standards but there is no current active project with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made. (4) See response to Q14. (5) For Requirements R5, R6, and R7, see comment on Requirement R3.		

Organization	Yes or No	Question 7 Comment

(6) The SDT has deleted the examples. See summary consideration for revision.

(7) The SDT agrees and has changed the language of the requirement to remove 'negatively'. The SDT has removed planned from Measure M9 to make the measure consistent with the requirement. Regardless of the reason for the outage, impacted entities need to be notified. See summary consideration for revision.

(8) The SDT agrees that the language of Requirement R10 could be clearer and has modified the language accordingly. The SDT does not believe it is necessary to split the requirement into two requirements. See summary consideration for revision.

(9) The SDT ultimately agrees that Requirement R11 belong in the BAL standards but there is no current active project with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made.

(10) The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The

Organization	Yes or No	Question 7 Comment
SDT did modify the requirement language to change “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. The SDT believes that SOLs can be identified by Real-time monitoring as well as through Real-time Assessments. No change made. (11) The SDT believe the proposed changes to Requirement R16 and R17 do not provide additional clarity and actually remove the true reliability intent of the requirement. The true reliability intent is that the System Operator has authority over his/her tools. The proposed changes removed System Operator. Furthermore, approval authority would grant authority to approve, deny, or cancel planned outages. No change made.		
PPL NERC Registered Affiliates	No	PPL does support the standard. We recommend the drafting team use only the term, ‘Facility Rating’ and not use the term ‘derived limit.’ This will provide for consistency is use of one term. Requirement #18, “Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits,” should be changed to ïƒ “, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in Facility Ratings.”
Response: The SDT has modified the requirement to reflect that derived limits are SOLs. See summary consideration for revision.		
Bureau of Reclamation	No	Reclamation disagrees with the use of the term Operating Instruction in IRO-001-4 R1. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Often Transmission Operators may not be aware of generation equipment constraints or other obligations (e.g. water delivery schedules for hydroelectric projects). Reclamation believes that IRO-001-4 should establish Transmission Operator authority to issue Reliability Directives to address an Emergency or avoid an Adverse Reliability Impact.

Organization	Yes or No	Question 7 Comment
Response: An Operating Instruction would include what was previously classified as directives, as per its definition, so proposed TOP-001-3 Requirements R1 and R2 already give the Transmission Operator authority to issue directives. No change made.		
BC Hydro and Power Authority	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: The SDT disagrees that Operating Instruction is too broad and that the standard should only apply in Emergencies. Failure to properly implement an Operating Instruction could be the initiating action that leads to an Emergency. This was the case in the September 2011 Southwest Outage. Also, an Operating Instruction would include what was previously classified as directives, as per its definition, so proposed TOP-001-3 Requirements R1 and R2 already give the Transmission Operator authority to issue directives. No change made. In the event that there is a conflict in Operating Instructions, the recipient can cite the clause "unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements" in Requirements R3 and R5 to resolve the situation. No change made.		
SPP Standards Review Group	No	We recommend the Real-time Assessment and Operational Planning Assessment definitions include the following change: 'The assessment may reflect inputs including, but not limited to: load, generation output levels,...' This will provide some flexibility for the TOP and BA to factor in those variables which can potentially impact

Organization	Yes or No	Question 7 Comment
		the assessments without being so overly prescriptive that they must be included in all assessments. We recommend deleting Requirements R1 and R2 because they are redundant to the entire collection of Reliability Standards. If a Transmission Operator or Balancing Authority does not do what is being required in R1 and R2, they are non-compliant with many of the remaining standards. This then appears to be redundant and these requirements should be deleted based on Paragraph 81 considerations. Insert a ‘to’ between the ‘do’ and the ‘due’ in the last line of the Rationale for Requirement R3. Replace ‘Transmission Operator’ in the 3rd line of M5 with ‘Balancing Authority’. Replace ‘Balancing Authority’ in the 6th line of M6 with ‘Transmission Operator’. We recommend the following language for Requirement R8: ‘Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of actual or expected conditions that it has identified which could potentially result in an Emergency.’ Requirement R9 requires the Transmission Operator to notify negatively impacted NERC registered entities. This is too broad and needs to focus on those entities which the Transmission Operator is aware that they are using the data and that the impact is of some significance. Additionally, this could prove to be burdensome on the industry for those situations where telemetry is repeatedly dropping out and restoring itself. We recommend the drafting team address the concept of significance and include a minimum down-time such as 30 minutes which is already incorporated in EOP-004-2, Attachment 1. Requirement R10 requires the Transmission Operator to monitor Facilities in neighboring Transmission Operator Areas in order to maintain reliability within its Transmission Operator Area. While we understand the intent of the requirement, we have concerns that in an audit situation or following an event, the question will be did the Transmission Operator go far enough into the neighboring Transmission

Organization	Yes or No	Question 7 Comment
		Operators Area. How far is far enough in this situation? Where does the responsibility for this monitoring transfer from the Transmission Operator to the Reliability Coordinator? Additionally, there appears to be redundancy between Requirement R10 and Requirement R1 in TOP-003-3 in that the later requests the data to allow for Real-time monitoring. We suggest eliminating Requirement R10. If the requirement must remain, we recommend the drafting team consider referring to the data requirement in TOP-003-3, Requirement R1 and specifically state that the extent of the data to be requested from neighboring Transmission Operators be determined by the Transmission Operator. Replace 'Tv' in the 3rd line of M12 with a subscripted 'Tv'. Regarding Requirement R13, please see our previous comments in response to Question 3 on IRO-008-2 associated with the 30-minute Real-time Assessment requirement. A similar argument holds for the TOP in TOP-001-3. Additionally, in the situation with smaller Transmission Operators, there may be an issue with the time required to acquire Real-time Assessment capabilities. For those smaller entities which may not be currently performing this role, it may take longer than a year for them to obtain this capability. Additional time should be provided in this situation. For example, TOP-003-3, Requirement R5 allows for more time for those entities which are not currently providing the data required in TOP-003-3, Requirement 1. A similar allowance should be included in Requirement R13. Replace 'Real-Time' in the 2nd line of M13 with 'Real-time'. Requirements R16 and R17 require the Transmission Operator and Balancing Authority, respectively, to provide its System Operators with the authority to approve planned outages of its monitoring and assessment capabilities. Does this apply to a single RTU or is it intended to cover only the full range of EMS capabilities? What is meant by 'derived limit' in Requirement R18?

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Response: The SDT agrees and has made the suggested change. See summary consideration for revision.

The SDT disagrees that the requirement to act in Requirements R1 and R2 is already covered in other reliability standards and without a specific reference do not see justification for modifying Requirements R1 and R2. However, some clarifying changes to reflect that the responsibility is to act to preserve reliability have been made. See summary consideration for revision.

The SDT has made a grammatical change to the rationale address your concern.

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

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

The SDT does not see that the proposed language provides any added clarity in Requirement R8. No change made.

The SDT disagrees that the requirement is too broad and believes that the Transmission Operator is in a position to know which entities outages of its telecommunications, control equipment, and monitoring and assessment capabilities will impact. It should be limited to those areas that are impacted by the loss of their transmission, generation, or load within their Transmission Operator Area. However, the SDT does agree that the requirement should be consistent with other standards. See summary consideration for revision.

The SDT has modified Requirement R10 to provide further clarification. The Transmission Operator will ultimately be responsible for determining what Facilities in neighboring areas they will need to monitor to assess the impact on the Transmission Operator Area. See summary consideration for revision.

The SDT disagrees that proposed TOP-003-3 Requirement R1 and proposed TOP-001-3 Requirement R10 are redundant. Proposed TOP-003-3 Requirement R1 is about the request for data. Proposed TOP-001-3 Requirement R10 is about monitoring and utilizing the requested data. The requirements are complementary. No change made.

The SDT has modified Measure M12 as requested. See summary consideration for revision.

For Requirement R13, see comment regarding IRO-008-2 in Q3.

The SDT disagrees with the need to extend the implementation period for Real-time Assessments. While they may not have been explicitly required, Real-time Assessments have always been necessary for a Transmission Operator. Transmission Operators are currently required to operate within all SOLs and IROLs. How can they do this without today performing a Real-time Assessment? No change made.

Organization	Yes or No	Question 7 Comment
The SDT has modified measure M13 as requested. See summary consideration for revision. Requirements R16 and R17 could certainly apply to a single RTU if it is impactful to reliability. Requirement R18 has been modified to clarify the requirement. See summary consideration for revision.		
ACES Standards Collaborators	No	(1) For Requirement R3, we question the phrase "cannot be physically implemented" and how that term would differ from violations of safety or equipment requirements. We recommend the SDT provide examples to support the new proposed language. (2) We recommend combining R4 with R3 and R6 with R5. Language could be easily added to notify the inability to comply with the Operating Instruction. This is the same comment for combing R6 with R5. (3) For Requirement R7, we question the need for this requirement since an entity is already subject to comply with Operating Instructions. Operating Instructions would include assistance relating to emergency procedures. This requirement is redundant and should be removed. (4) Requirement R8 is problematic as currently written. At what point must a TOP notify the RC, BA, and other TOPs of "expected operations that could result in an Emergency?" We recommend focusing on actual operations that result in actual Emergencies. Furthermore, examples do not belong in a requirement and should be moved to the application guidelines. (5) For Requirement R9, what is the timing of notifications? The requirement does not define "negatively impacted interconnected NERC registered entities" and therefore is vague. Can other entities be positively impacted? We recommend clarifying this requirement. (6) We disagree with Requirement R10 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. TOP-001-3 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity. Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly

Organization	Yes or No	Question 7 Comment
		impact reliability, are redundant, and handle data requests and submittals. Further, asking for non-BES data is out of scope of the jurisdictional bounds of reliability standards. (7) For Requirement R13, we ask the SDT to clarify that registered entities are not required to install real-time state estimation to perform its Real-time Assessments and can rely on other methods to perform the assessment such as reviewing its RC's results. (8) For R14, the language is confusing. We suggest changing "as part of its" to "identified in its." This will make clear that the SOL is identified in the Real-time monitoring or Real-time Assessment. (9) For Requirement R15, we question the value of TOPs stopping what they are doing to alleviate a SOL violation to call the RC to tell them their plan. It seems to make better sense for the TOP to focus on the returning the SOL to within limits when it is exceeded and contact the RC if the TOP enters into an Emergency. (10) For Requirement R18, how does the drafting team define "derived limits"? This requirement is unnecessary because the TOP, BA, and GOP are required to comply with Operating Instructions.

Response: (1) Regarding the term "cannot be physically implemented" in Requirement R3, it is intended to cover the category that has always been a gap in the standard. For example, if a Transmission line is out of service and wire has been removed for re-conductoring, the line cannot be physically put back into service. This is not really a safety, equipment limit, regulatory or statutory issue. No change made.

(2) The SDT does not believe that combining Requirement R4 with Requirement R3 and Requirement R6 with Requirement R5 provides any additional clarity. No change made.

(3) The SDT disagrees that Requirement R7 is redundant with other requirements in this standard and unneeded. Requirement R7 differs from Requirement R3 in that Requirement R3 does not allow a Transmission Operator to Transmission Operator directive. Requirement R5 is not relevant since it involves following a Balancing Authority's directives and Requirement R7 involves assisting a Transmission Operator so they are initiated by two different entity types. The SDT agrees that Requirement R7 could be viewed as

Organization	Yes or No	Question 7 Comment
partially redundant with Requirement R3 for a Balancing Authority complying with a Transmission Operator issued Operating Instruction and will remove the Balancing Authority from the requirement. The SDT has made other modifications to the requirement based on other comments as well. See summary consideration for revision. (4) The Transmission Operator must notify the Reliability Coordinator when it is in an Emergency or anticipates that it could quickly be in an Emergency due to some event. For example, if an SPS was suddenly and unexpectedly disarmed, there may not yet be an Emergency but if a Contingency were to happen, there likely would be an Emergency. The Reliability Coordinator needs to be aware of these situations. The SDT agrees that the examples for Requirement R8 are not necessary and has deleted them. No additional changes beyond removing the examples made. See summary consideration for revision. (5) The SDT has made clarifying changes to Requirement R9 including removing "negatively". See summary consideration for revision. (6) The SDT has modified Requirement R10 for clarity. See summary consideration for revision. (7) The SDT was very intentional in writing the definition of Real-time Assessment to allow for third-party services. Thus, Requirement R13 is not intended to require a Transmission Operator to have state estimation and real-time contingency analysis. Other methods may be relied upon included utilizing the Transmission Operators Reliability Coordinator's results. The SDT has modified Requirement R13 and the definition of Real-time Assessment to further clarify this understanding. See summary consideration for revision. (8) Requirement R14 has been modified as requested along with additional modifications based on other comments. See summary consideration for revision. (9) The SDT agrees that the Transmission Operator should not stop what it is doing to alleviate a SOL to notify the Reliability Coordinator of its actions in Requirement R15. However, the SDT does believe there will be time in between actions or immediately after taking an action but prior to full implementation of said action (e.g., re-dispatch) to notify the Reliability Coordinator. No change made. (10) The SDT has clarified Requirement R18. Derived limits are SOLs. The SDT disagrees that the requirement is not needed because Transmission Operators and Balancing Authorities must follow directives. However, the SDT has removed Generator Operator based on this reasoning. See summary consideration for revision.		

Organization	Yes or No	Question 7 Comment
ISO/RTO Standards Review Committee (SRC)	No	Regarding R2, did the SDT consider whether putting a "transmission operations" requirement on a Balancing Authority was appropriate? We do not agree with Requirements R2, R5, R6, R7, R9, R11, R17 and R18. Requirement R2 stipulates that "Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area." This requirement seems out of place. The purpose of the standard is to ensure transmission operating reliability, not resource adequacy, balancing capability or frequency performance. The BA is not required to have any transmission information, and it does not have any sole responsibilities in ensuring transmission reliability other than responding to instructions by its TOP or RC to manage resource-demand-interchange balance or interchange schedules to assist in mitigating transmission constraints. With respect to implementing the IERP's and OC's recommendation to ensure BA has the authority to act or direct others to act, any such requirements (to maintain resource-demand-interchange balance or meet frequency performance targets) should be placed in the BAL standards or the EOP standards, but not in a TOP standard. We suggest R2 be removed. In addition, Requirements R5 and R6 should be removed as well. For Requirement R7, we do not see the need to include the Balancing Authority since it is supposed to comply with the Operating Instructions of its Transmission Operator (in R3). We believe the proposed R7 is a revised version of R4 of TOP-001-2, which was approved by the NERC BoT in May 2012. Requirement R4 in TOP-001-2 did not include the BA as a responsible entity. We suggest removing the BA from R7. Requirement R9 stipulates that: "Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities."

Organization	Yes or No	Question 7 Comment
		The last part appears to be unclear as the "affected entities" can be interpreted as any two entities not including the one that is experiencing or anticipating outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. In that case, the entity that is held responsible for notifying others of its existing or anticipated outages will have no knowledge if the "associated communication channels between affected entities" will have an outage and if so, whether such an outage will negatively affect others. We suggest the last part be revised to "between it and the affected entities". Requirement R11 is out of place for the similar reasons indicated for R2, above. We suggest removing this requirement, or move it to the appropriate BAL or EOP standard. Requirement R17 is out of place for the similar reasons indicated for R2 and R11. We suggest moving this requirement to the appropriate BAL or EOP standard. Requirement R18 should not include the Balancing Authority since it does not operate any Facilities for which there are limits derived by more than one entity, unlike its TOP or RC counterpart. Comments R1: We do not agree with the rationale for this requirement. If an RC does not act he will be in violation of other requirements and therefore a possible double jeopardy. The previous requirement R3, obligated an RC to have authority from someone to ensure that they could take actions which is now absent. Comment R7: We believe the previous language should be retained to limits the assistance up to and including emergency procedures implemented by the requesting entity. As worded, this could expose the assisting entity to violations for not going beyond what has been implemented. Comment R8: Should remove "or could result in" since it is unmanageable to inform all possibly impacted entities of all possible contingencies.

Organization	Yes or No	Question 7 Comment
		Comment R9: How does one access a potential negative impact? To what extent would negatively impacted entities need to be notified? Could it involve even governor response? Also, is this for planned or actual outages? The measure states planned, the requirement doesn't. How will this coordinate with COM-001 R3? Comment R10: The phrase 'including sub-100 kV' is not needed. If the sub 100 kV facility impacts the BES in such a manner, it should be labeled a BES facility per the inclusions in the new definition. Comment R13: We ask that the drafting team confirm that Real-time Assessments are not limited to software applications specifically a contingency analysis tool. How is this coordinated with EOP-004 for reporting tool outages exceeding 30 minutes?

Response: Requirement R2 is intended to require the Balancing Authority to focus on its reliability functions (i.e., balancing Load, interchange, generation) not transmission operations. No change made.

The SDT ultimately agrees that Requirements R2, R5, R6, R11, and R17 belong in the BAL standards but there is no current active project that with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made.

The SDT agrees and has removed Balancing Authority from Requirement R7. See summary consideration for revision.

The SDT has modified Requirement R9 but does not agree that a time limit is needed. See summary consideration for revision.

The SDT disagrees that a Balancing Authority should not be included in Requirement R18. While a Balancing Authority may not derive SOLs, they certainly do operate to them in certain cases. No change made.

Requirement R1 does not apply to the Reliability Coordinator. No change made.

The SDT believes Requirement R7 has been structured appropriately. First, the requester has to already have implemented its emergency procedures so it is an Emergency. Second, the requirement includes several caveats (i.e., statutory, regulatory, safety, equipment limits, and inability to physically implement). If none of these conditions are met, why would the assisting entity not provide additional assistance? The SDT has made changes for clarity based on comments received. See summary consideration for revision.

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Requirement R8 does not require the Transmission Operator to notify impacted entities of all possible Contingencies. Most Contingencies will not result in an Emergency. Only a small subset will. The SDT believes it is appropriate to notify the impacted entities of these Contingencies. No change made.

Requirement R10 has been modified for clarity based on comments received. See summary consideration for revision.

The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.

Organization	Yes or No	Question 7 Comment
Bonneville Power Administration	No	Since entities will need to accurately interpret several requirements in the Standard, BPA suggests adding the System Operating Limit (SOL) Definition and Exceedance Clarification white paper to the Standard as an appendix. BPA believes the language in requirements R8 and R14 is too ambiguous and open-ended. As a result, this would likely lead to decisions based on assumptions. BPA suggests both requirements be tied to an operating procedure or process, which, in turn, can be left to each applicable entity to define. 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, and include parameters for possible events, so that applicable entities are not required to predict all possible future events.
Response: The SDT agrees to include the whitepaper in the application guidelines or an appendix of the standard. The SDT has made modifications to both Requirements R8 and R14 that provide clarifications. See summary consideration for revision. Due to the non-specificity of the last comment, the SDT has no response. The SDT has no idea which requirements are problematic for you and can't address your concern as a result. No change made.		
Georgia System Operations	No	R1 and R2 - Request that Requirements 1 and 2 are high level and generic and that the requirements do not seem results-based. R7 - The Rationale section for Requirement R7 states that the word 'Emergency' was deleted and the word 'Effective' was added to the Requirement language. The word 'Effective' is missing from the Requirement language. Since Operating Instructions are specific to the operation of the interconnected Bulk Electric System, we believe the purpose statement should be revised to be consistent with the terms being utilized and to be consistent with other Standards closely

Organization	Yes or No	Question 7 Comment
		associated such as COM-002-4. We recommend replacing the terms “reliability of the Interconnection” with the terms “reliability of the Bulk Electric System (BES)”. The current proposal for R3 and R5 as written could overly expose the DP and LSE excess compliance obligations for routine switching operations performed on a daily basis which does not affect the reliability of the BES such as maintenance items, etc. The DP and LSE implement operating instructions on non-BES equipment on a routine basis, but the implementation of operating instructions on BES equipment, or non-BES equipment “affecting the reliability of the BES” is not very routine. The intent of this requirement should be for the DP/LSE should complement COM-002-4 R6 relating to Operating Instructions during an Emergency “affecting the reliability of the BES”. The use of the NERC term “Emergency” would capture this intent. We propose the language “[during an Emergency]” be added after “....shall comply with each Operating Instruction issued by its Transmission Operator(s) [ ] “. R8 - We suggest that the phrase ‘could result in’ is too open ended and assumes that operations takes place as expected and does not account for failures and equipment during the operations such as faulted breaker, or human performance errors. R9 - Add the word ‘planned’ to Requirement language to match Measure language.R9 - The phrase ‘negatively impacted Interconnected NERC registered entities’ seems broadly generic. GSOC suggests adding the words, ‘other affected adjacent BAs and TOPs’. R16 and R17 - These requirements only address planned outages of monitoring and assessment capabilities while the corresponding RC requirement in the IRO standards address maintenance of such capabilities as well. The SDT should review for consistency purposes. R16 and R17 - These requirements state that the TOP and BA shall provide its System Operators with the authority to approve planned outages of its own monitoring and analysis capabilities. Is clarification needed to reflect that the RC can override the authority given to System Operators as stated in R1 of EOP-002-2.1 (The RC has the

Organization	Yes or No	Question 7 Comment
		ultimate responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and responsibility and shall exercise specific authority to alleviate capacity and energy emergencies.) R18 - There is confusion in the Industry of what the current term 'derived limits' means. The SDT should take this opportunity to clarify whether 'derived limits' is referring to SOLs, IROLs. If this is the case, then why use the term, 'derived limits'?

Response: The SDT has made every effort to employ results-based methods in the revisions. No change made.

The SDT agrees and has updated the rationale for Requirement R7.

Standards are written for the reliability of the BES so the SDT finds the suggested change to be redundant. No change made.

The SDT disagrees that Requirements R3 and R5 should only apply in Emergencies as failure to properly implement an Operating Instruction could be the initiating action that leads to an Emergency. This was the case in the September 2011 Southwest Outage. However, in response to other comments, the SDT has modified Requirements R1 and R2 to reflect that these are Operating Instructions issued to preserve reliability on the BES. See summary consideration for revision.

The SDT disagrees that Requirement R8 is too broad. Requirement R8 appropriately requires the Transmission Operator to notify impacted entities of operations that could result in an impact. This requirement and the standard as a whole does consider the impact of stuck breakers along with other impactful contingencies. A Transmission Operator is required to operate within SOLs and IROLs. Approved FAC-011 Requirement R3, Part 3.3 already requires the Reliability Coordinator's SOL methodology to include multiple Contingencies such as a stuck breaker. No change made.

The SDT has removed planned from Measure M9 to match the requirement. Notice of outages of tools and monitoring capabilities is important regardless of the cause. The SDT disagrees that the requirement is too broad and believes that the Transmission Operator is in a position to know which entities outages of its telecommunications, control equipment, and monitoring and assessment capabilities will impact. It should be limited to those areas that are impacted by the loss of its Transmission, generation, or Load within its Transmission Operator Area. However, the SDT has modified the requirement based on other comments to be consistent with other standards See summary consideration for revision.

Organization	Yes or No	Question 7 Comment
The SDT disagrees that this requirement should only apply to planned outages. If a Balancing Authority's or Transmission Operator's ICCP connection experiences an unexpected outage, they absolutely should be required to notify the other impacted entities. No change made. The SDT notes that there are slight differences between proposed TOP-001-3 Requirements R16 and R17 and the comparable IRO requirement and will make corresponding changes to align the requirements. The core purpose of the requirements which is the System Operator shall have approval authority of monitoring and analysis capabilities is not different. See summary consideration for revision. The SDT does not believe that additional clarification is needed to indicate that the Reliability Coordinator has authority over the Transmission Operator and Balancing Authority and can override their decision to approve outages of their capabilities. The Reliability Coordinator already has the authority to issue directives to these entities. No change made. The SDT agrees that derived limits can be made more specific and has modified the language of the requirement. See summary consideration for revision.		
Rayburn Country Electric Cooperative	No	I believe clarity and efficiency could be achieved by combining IRO-001-4 and TOP-001-3.Both Standards are intended to insure reliability of the interconnection. The IRO standards family itself is "Interconnection Reliability Operations and Coordination" and the purpose statement for TOP-001-3 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." The strategy could be accomplished by defining the responsibilities by two groups, those that have the authority to deliver an Operating Instruction and the second group as those who need to receive and act on an Operating Instruction. This would allow 6 requirements in my example to follow, to be condensed into 2 requirements. Delivering Entity Any one of the following functions: o Reliability Coordinator, o Balancing Authority, o Transmission Operator Receiving Entity Any one of the following functions: o Balancing Authority, o Transmission Operator, o Transmission Service Provider, o Generator Operator, o Load Serving Entity o Distribution Provider R2 Receiving Entity shall comply with the Delivering Entities Operating Instructions unless compliance with the Operating Instructions cannot be

Organization	Yes or No	Question 7 Comment
		physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. R3 Receiving Entity shall inform the Delivering Entity of its inability to perform the Operating Instruction issued by its Delivering Entity in Requirement R2 citing one of the specific reasons shown in Requirement R2.
Response: The SDT appreciates your creative approach to consolidating and simplifying requirements but believes all of the requirements are necessary and must be separate to reflect the operational hierarchical structure. For instance, Requirement R3 does not apply to a Transmission Operator because a Transmission Operator cannot issue operating instructions to another Transmission Operator. Requirement R5 is similar in that a Balancing Authority cannot issue Operating Instructions to other Balancing Authorities. However, a Reliability Coordinator can issue Operating Instructions to both. Combining the requirements and respecting this operational hierarchy would make the requirements quite cumbersome. In addition, this project inherited the scope of Projects 2006-06 and 2007-03 which indicated industry preferences for keeping the functions separate. No change made.		
CenterPoint Energy Houston Electric LLC.	No	CenterPoint Energy believes that some of the items in the proposed definition of Real-time Assessment are redundant. CenterPoint Energy recommends removing “known Protection System and Special Protection System status or degradation” as well as “equipment limitations.” These are encompassed in Transmission outages, generator outages, and Facility Ratings and do not need to be identified separately. CenterPoint Energy also feels “identified phase angle limitations” are not applicable in all Regions and should be addressed under Section D, Regional Variances. CenterPoint Energy believes the proposed language in R1, “...shall act, or direct others...” brings in new compliance concerns that were not present in the previous versions of TOP-001, R1. CenterPoint Energy recommends returning to the language in previous versions stating, “Each Transmission Operator shall have the responsibility and clear decision making authority to take whatever actions are needed to ensure reliability...” If the SDT agrees with this approach, CenterPoint Energy recommends conforming changes to TOP-001-3 R2 and IRO-001-4 R1 for the Balancing Authority and Reliability Coordinator’s responsibility, respectively.

Organization	Yes or No	Question 7 Comment
		CenterPoint Energy believes inconsistencies exist between R1 and R3. R1 states, "Each Transmission Operator shall act, or direct others within its Transmission Operator Area to act by issuing Operating Instructions..." A NERC defined Transmission Operator Area is the collection of Transmission assets over which the Transmission Operator is responsible for operating. R3 states, "Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s)..." BAs, GOPs, DPs, and LSEs do not fall into a Transmission Operator's Transmission Operator Area as defined. CenterPoint Energy recommends the SDT review the language in R1 and R3 to determine if any modifications are required to remedy this inconsistency. CenterPoint Energy believes R7 is redundant with issuing and following Operating Instructions as described in TOP-001-3 R1 and IRO-001-4 R1. If assistance is needed under emergency or anticipated emergency conditions, the Transmission Operator or the Reliability Coordinator will issue an Operating Instruction as described in TOP-001-3 R1 or IRO-001-4 R1, respectively. CenterPoint Energy recommends deleting this Requirement. CenterPoint Energy believes R10 is vague in its expectation of monitoring Facilities of neighboring Transmission Operator Areas to maintain reliability. CenterPoint Energy believes it is the Reliability Coordinator's responsibility to monitor and address seams issues that may extend from one Transmission Operator Area to another Transmission Operator Area. CenterPoint Energy recommends the following change to the language of the Requirement or reassigning the Requirement to the Reliability Coordinator: R10. Each Transmission Operator shall monitor Facilities within its Transmission Operator Area including sub-100kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area.

Response: The SDT does not believe that the items cited are redundant or could cause confusion. No change made.

Organization	Yes or No	Question 7 Comment
The SDT disagrees that identified phase angle limitations are not applicable in all regions and that they should be covered under a regional variance. While some regions may not have any specific issues, the possibility does exist for them to be an issue or they could develop at a later date. If an entity does not have such issues, they will not be identified and subject to the definition. No change made. The SDT agrees that the definition of Transmission Operator Area could be interpreted to exclude Load-Serving Entities and Distribution Providers. The SDT has modified the requirement to address comments. See summary consideration for revision. The SDT disagrees that Requirement R7 is redundant with other requirements in this standard and unneeded. Requirement R7 differs from Requirement R3 in that it does not allow a Transmission Operator to Transmission Operator directive. Requirement R5 is not relevant since it involving following a Balancing Authority's directives and Requirement R7 involves assisting a Transmission Operator so they are initiated by two different entity types. The SDT agrees that Requirement R7 could be viewed as partially redundant with Requirement R3 for a Balancing Authority complying with a Transmission Operator issued directive and will remove the Balancing Authority from the requirement. The SDT has made other modifications to the requirement based on other comments as well. See summary consideration for revision. The SDT disagrees that the Transmission Operator should only monitor Facilities within it Transmission Operator Area. Facilities outside of its Transmission Operator Area impact the reliability of its area and the Transmission Operator should be monitoring these facilities. However, the SDT has modified the requirement to provide some additional clarification regarding monitoring into a neighboring Transmission Operators Area. See summary consideration for revision.		
Exelon Companies	No	Exelon agrees with all but one aspect of the proposed standard.R18. Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits. R18 previously included other entities as identified in the Rational including the LSE, PSE, DP and TSP. The rational statement says deleting these entities is being done "as those entities will receive instructions on limits from the responsible entities cited in the requirement". Exelon Generation believes the GOP belongs in the same category as the above deleted entities for this requirement. We note that "derived limit" is an undefined term. It may be a term of art in the TOP lexicon but it is not commonly used or understood by GOP's. In dozens of audits, no auditor has been able to tell us (Exelon Generation Company, Nuclear and Fossil)

Organization	Yes or No	Question 7 Comment
		what this means with respect to a generator operator. The TOP may derive limits on the transmission system but in our experience the GOP does not. The GOP provides facility status information, GSU limits etc. that the TOP can use to calculate /model / derive the limits on the transmission system. Providing facility status and following Directives and Operating Instructions is a GOP responsibility, deriving limits implies information about a dynamic system being modeled and evaluated so as to determine the limits to transmission system operation which is a TOP and or a RC responsibility. As background, we point out that the pre version 0 NERC Operating Guide 200 from which this requirement appears to come did not include the GOP and the ver. 0 standard IRO-005 R13 did not include the GOP in the applicability for this standard (all above Rational 18 deleted entities and GOPs were added in IRO-005 R13 text but not included in the applicability for the standard). Changes to the applicability section of IRO-005 that included these entities was later added via an errata. This issue and a cogent FERC response to it was identified in Order 693944. TAPS raises an issue with Requirement R13 that states in part "[i]n instances where there is a difference in derived limits,...Load-Serving Entities...shall always operate the Bulk Electric System to the most limiting parameter." TAPS further states that, since LSEs do not operate the system within SOLs or IROLs, the only thing such entities, particularly small ones, can do is shed load.950. We [FERC] do not share TAPS' concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS' concern in developing the modification of this Reliability Standard.
Response: The SDT has modified the requirement to reflect that derived limits are SOLs. The SDT agrees that the Generator Operator should not be included for the purpose of SOLs because they will have no knowledge of these limits. Furthermore, the		

Organization	Yes or No	Question 7 Comment
Transmission Operator and Reliability Coordinator could simply direct the Generator Operator to adjust unit outputs to operate within established SOLs. See summary consideration for revision.		
City of Garland	No	Requirement 1 Concern # 1The volume of applicable Reliability Standards already requires action or directing others to act. In an audit situation, the NERC auditor cannot find a possible violation for failing to “act or direct others to act” without also identifying which Requirement in which NERC standard that required action - therefore, there is already an existing requirement to act or direct others to act without this proposed requirement. Recommendation # 1Replace this proposed requirement with the existing requirements concerning authority. Concern # 2The “act, or direct others to act” is executed by experienced, NERC Certified Personnel who make decisions in real-time based on the information available at that time. To continuously compile supporting information to support each decision / action taken by experienced, NERC Certified Personnel for an audit situation will be time consuming, labor intensive and will require voluminous data storage. Also, unless there is some event that triggers an event analysis, how is the auditor going to determine the “when”, “what” and “how” in a normal audit months or years later to decide whether the entity is in violation. Sometimes the correct action to take is “no action” based on the information available at the time. Recommendation # 2 Replace this proposed requirement with the existing requirements concerning authority. Requirement 2 Same concerns as listed under question 7 - Requirement 1 Requirement 10 Concern: “shall monitor Facilities within its TOP Area and neighboring TOP Areas” - The “and neighboring TOP Areas” is too vague and too open to interpretation - should not be left to an auditor’s opinion during an audit situation to determines what facilities and how “deep” into neighboring TOP Areas must be monitored to be compliant. Recommendation: delete “and neighboring TOP Areas” Requirement 13 Concern 1There is no provision to allow for any number of reasons why a Real-time Assessment might not be completed on a 30 minute cycle without it

Organization	Yes or No	Question 7 Comment
		being a violation - any way one looks at it, “life is not perfect” and an entity (the TOP) should not be fined or spend financial / personnel resources to work through a potential violation every time a Real-time Assessment fails to complete. Concern 2 There is no provision for small Transmission Operators who’s Area (number / size of Facilities) is too small to financially justify installing this capability - all TOPs are not created equal.

Response: The SDT disagrees and believes that the replacement of the authority language with the action language is the correct approach. No change made.

The SDT has modified data retention for this requirement to minimize the burden will be associated with this requirement. See summary consideration for revision.

The SDT disagrees that the Transmission Operator should only monitor Facilities within its Transmission Operator Area. Facilities outside of its Transmission Operator Area impact its reliability and the Transmission Operator should be monitoring these facilities. However, the SDT has modified the requirement to provide some additional clarification regarding monitoring into a neighboring Transmission Operators Area. See summary consideration for revision.

The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability.
The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity’s Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Organization	Yes or No	Question 7 Comment
The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of “Real Time Assessment” does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking “alternative actions” and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator’s Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. The SDT was very intentional in writing the definition of Real-time Assessment and Requirement R13 to allow for third-party services. Thus, Requirement R13 is not intended to require a Transmission Operator to have state estimation and Real-time Contingency analysis. Other methods may be relied upon included utilizing the Transmission Operator’s Reliability Coordinators results. The SDT has modified Requirement R13 and the definition of Real-time Assessment to further clarify this understanding. Smaller entities today must have a way to assess their system in Real-time, whether this is relying on operational planning studies, system knowledge, its own Real-time Contingency analysis or possibly its Reliability Coordinator’s. Otherwise, how can a small entity determine it is operating within first Contingency? See summary consideration for revision.		
Ingleside Cogeneration LP	No	ICLP believes the changes made to TOP-001-3 have reintroduced enormous administrative overhead into our compliance approach for Operating Instructions. That issue was resolved in COM-002-4 by focusing on the training of GOP front-line operators who receive Operating Instructions - not their actual execution. This was a necessary step because the range of communications that constitute an Operating Instruction is very broad, and it is unreasonable to expect that every one of them will be perfectly executed and documented to the liking of an audit team. The problem is that there are two distinct categories of interest. The first are those which are issued as an urgent action, and which are really the target of TOP-001-3. It is appropriate to expect that those Operating Instructions issued during Emergencies and near-Emergencies should be handled in a zero-tolerance manner. However, those issued in the normal course of business - by far the larger category - must be excluded. TOP-

Organization	Yes or No	Question 7 Comment
		001-4 R1 and R2 provides no limitations on applicable Operating Instructions. This ambiguity can be resolved in different ways. The drafting team could add language back to Requirements R1 and R2 specifically limiting their applicability to a set of defined circumstances. A better method may be to require the TOP or the BA to identify the Operating Instruction as “critical” to the recipient in order to heighten awareness and ensure compliance. Furthermore, ICLP believes that a qualifier must be added to R3 and R5 for the Operating Instruction recipient to notify the issuer “upon recognition” of its ability to perform it. This language would account for situations where the inability to act is recognized sometime after the instruction is issued. This happens in real-time and it is not appropriate to penalize an entity who initially believes that they can execute a critical Operating Instruction in good faith - but finds out later they cannot. Lastly, ICLP does not agree with the intent and language of Requirement R18. This poorly defined requirement has been transferred from IRO-005 - and has been inconsistently applied by CEAs. R18 leaves it to the GOP to operate to someone’s most “limiting parameter” if there is a conflict with someone else’s “derived limits”. This seems to infer those transmission Facility Ratings, SOLs, or IROLs maintained by the RC and TOP - parameters which GOPs do not monitor. Those difference should be resolved between TOPs and RCs, who then must inform the GOP what the proper limits are.
Response: While the SDT agrees that Operating Instructions issued during Emergencies are very important, failure to follow an Operating Instruction issued during normal operating conditions can and has led to actual Emergencies. This was the case in the September 2011 Southwest Outage. No change made. The SDT does not believe the proposed modifications to Requirements R3 and R5 provide any clarification. The requirements as written require the responsible entity to comply with the Operating Instruction unless it can’t for one of the allowed reasons. Then, it must notify the issuer. This could only occur once they recognize it. No change made. The SDT agrees that the requirement should not apply to Generator Operators and has modified the requirement. See summary consideration for revision.		

Organization	Yes or No	Question 7 Comment
American Transmission Company	No	ATC requests that the SDT consider the following recommended modifications: a. Real-time Assessment definition - ATC suggests the definition be reworded as follows for added clarity. "An evaluation of system conditions using Real-time data to assess contingency conditions, limited to the single Contingency loss of a generator, line, transformer or shunt device and multiple outages as specified by its RC, to assess potential operating conditions." Otherwise, ATC suggests the following changes to the definition: Modify the first sentence of the definition by adding the word "single" to read, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-single Contingency) operating conditions." Otherwise, ATC suggests adding a sentence to the proposed definition to read, "Contingency conditions are limited to the most severe single contingency and the multiple outages specified by its Reliability Coordinator." b. R1 - For clarity, ATC recommends that Requirement R1 be modified to define "others" as "DP(s), LSE(s), BA(s) and GOP(s)." c R2, R11, R17 - N/A d. R3 - ATC agrees with the proposed TOP-001-3 Requirement R3. e. R4 - ATC agrees with the proposed TOP-001-3 Requirement R4. f. R5 - ATC agrees with the proposed TOP-001-3 Requirement R5. g. R6 - ATC agrees with the proposed TOP-001-3 Requirement R6. h. R7 - ATC agrees with the proposed TOP-001-3 Requirement R7. i. R8 - ATC has no comment regarding Requirement R8. j. R9 - Notification of telemetering and telecommunication outages. The SW Outage Report recommendation is specific to reporting technical issues with their contingency analysis capabilities after the functionality is lost. Therefore, ATC recommends the requirement should be revised as follows to only address forced or unexpected outages. "R9. Each Balancing Authority and Transmission Operator shall

Organization	Yes or No	Question 7 Comment
		notify its Reliability Coordinator and (removed negatively) potentially impacted interconnected NERC registered entities of forced outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” k. R10 - ATC sees Requirement R10 as ambiguous regarding what is being monitored. It is unclear if the TOP is to monitor topology changes, analog values for violation, and/or model neighboring TOP contingencies in its Real-time Assessments for the neighboring TOP system. In addition, the current wording does not clearly state which sub-100 kV facilities are to be monitored (i.e., its TOP area or the neighboring TOP area). ATC recommends splitting the requirement into two parts to address these issues. ATC recommends rewording Requirement R10 as follows:”R10. Each Transmission Operator shall monitor BES Facilities and the status of Special Protection Systems within its Transmission Operator Area needed to maintain reliability within its Transmission Operator Area, including non-BES Facilities needed to maintain reliability.” l. ATC recommends Requirement R10.1 be added prepared as follows: “R10.1. Each TOP shall monitor system topology changes within neighboring Transmission Operator Areas, including non-BES Facilities, to maintain reliability within its Transmission Operator Area.” m. R12 - ATC agrees with the proposed TOP-001-3 Requirement R12. n. R13 - ATC provides the following suggestions regarding Requirement R13. Perform Real-time Assessment at least once every 30 minutes. Paragraphs 55 and 60 (of the NOPR) do not specifically require a timeframe for monitoring and assessment capabilities. Therefore, it is recommended to remove the Real-time Assessment at least once every 30 minute requirement. In addition, NERC has already developed the ERO Event Analysis Process Document to address reporting the loss of monitoring or control at control centers (which includes unacceptable State Estimator or Contingency Analysis solutions) and should provide adequate assurance of industry performance related to control center situational awareness tools. If the SDT retains

Organization	Yes or No	Question 7 Comment
		the requirement, ATC recommends developing a performance-based requirement as opposed to a single time limit in which the Transmission Operator would be required to report for every excursion. Example - CPS1 / CPS2 BA performance metrics. o. R14 - If ATC's first proposal for changing the definition of "Real-Time Assessment" is not implemented, ATC feels that the language in Requirement R14 should be improved modified by removing some redundancy and adding clarity. ATC suggests the removal of "Real-time monitoring" from the proposed requirement since the "Real-time Assessment" definition already requires assessing existing operating conditions. In addition, ATC suggests the addition of "within its Transmission Operator Area" to R14 to provide clarity and be consistent with the language proposed for TOP-002-4. ATC suggests the language of Requirement R14 read as follows:"R14. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance within its Transmission Operator Area identified as part of its Real-time Assessment." p. R15 - ATC agrees with the proposed TOP-001-3 Requirement R15. However, ATC suggests development of a similar requirement applicable to Interconnection Reliability Operating Limits (IROLs). q. R16 - If ATC's first proposal for changing the definition of "Real-Time Assessment" is not implemented, the language in Requirement R16 should be modified by removing some redundancy and adding clarity. ATC suggests the removal of "monitoring" from the proposed Requirement R14 since the "Real-time Assessment" definition already requires assessing existing operating conditions. ATC also suggests the addition of "within its Transmission Operator Area" to R16 for added clarity. ATC suggests the requirement be reworded as:"R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages of its own Real-time Assessment capabilities within its Transmission Operator Area." r. R18 - To improve clarity and be consistent with proposed definitions, ATC suggests revising Requirement R18 by replacing the term "derived operating limits" as indicated in the following revision of the requirement:"R18. Each Transmission

Organization	Yes or No	Question 7 Comment
		Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting real-time (pre-Contingency) or potential (post-Contingency) operating condition in instances where there is a difference in SOLs or Real-time Assessments.”

Response: a. The SDT does not believe that the proposed changes provides any additional clarification and actually may create confusion by conflicting with approved FAC-011 Requirement R3, Part3.3 which already requires the Reliability Coordinator to identify which multiple Contingencies are applicable to the SOL methodology. Thus, all Contingencies would be single Contingencies unless a multiple Contingency is identified by the Reliability Coordinator’s SOL methodology. No change made.

b. The SDT does not believe identifying others in Requirement R1 is necessary as “others” would be those obligated to respond in Requirement R3. No change made.

c. – i. The SDT thanks you for your agreement.

j. The SDT disagrees that notification for monitoring capability outages should only occur with forced or unplanned outages. Regardless of the reason for the outage, other entities need to know about the outage so they can increase their vigilance in monitoring. The Reliability Coordinator in particular would then monitor the Transmission Operator or Balancing Authority with the monitoring capability outage more closely. The SDT does agree with removing “negatively” from the requirement. No additional changes made. See summary consideration for revision.

k. and l. The SDT disagrees that Requirement R10 should be split into two requirements but has modified the requirement for clarity. See summary consideration for revision.

m. Thank you for your agreement.

n. The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity’s Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time

Organization	Yes or No	Question 7 Comment
		Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. o. The SDT disagrees and believes that Real-time monitoring can find violations. No change made.. p. The SDT thanks you for your agreement with Requirement R15. However, the SDT does not believe that a similar IROL requirement is necessary for the Transmission Operator. There is a parallel IROL requirement that is applicable to the Reliability Coordinator. Responsibilities for IROLs and SOLs have been divided in the standards with the Reliability Coordinator having primary IROL responsibility and the Transmission Operator having primary SOL responsibility. No change made. q. The SDT does not believe the proposed addition to Requirement R16 provides any additional clarity. The Transmission Operator could not approve an outage of its neighbors monitoring capability, it could only approve an outage of its own capability. While its neighboring Transmission Operator may approve an outage of its own monitoring and Real-time Assessment capabilities and these outages may impact other Transmission Operators, a Transmission Operator still cannot approve its neighbor's outages. No change made. r. The SDT has clarified Requirement R18. Derived limits are SOLs. See summary consideration for revision.

Organization	Yes or No	Question 7 Comment
American Electric Power	No	R8: Needs additional clarity and consistency with other requirements. A TOP is able to communicate any emergencies they see/foresee in their system and communicate these issues to the RC and entities known to be directly-impacted. The RC would have the wide-area view necessary to determine any impacts to other BAs or TOPs. However, a TOP would have limited ability to know if they're creating any impact regarding other BAs or TOPs that aren't interconnected with them. The standard should be changed to require the RC, not the TOP, provide such communication. R9: The requirement needs to specify which “negatively impacted interconnected NERC registered entities” need to be notified in order to be consistent with R8 and other requirements. R10: It is not clear exactly which sub-100 KV Facilities need to be monitored by the TOP. In addition, the TOP is in the best position to make this determination. The requirement should be changed to allow the TOP flexibility to identify which facilities are to be monitored.
Response: The SDT agrees that the Transmission Operator may not know the full impact of its operations which is the reason there are Reliability Coordinators. However, the Transmission Operator should know if it impacts the Balancing Authority. The requirement has been modified accordingly. See summary consideration for revision. The SDT disagrees and does not believe that the suggested change adds clarity. No change made. Requirement R10 was always intended for the Transmission Operator to make the determination of which of its neighboring Transmission Operator's Facilities it needs to monitor. The requirement has been modified to provide additional clarification. See summary consideration for revision.		
NIPSCO	No	1. 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. 2. In R8 NIPSCO would like the term “emergency” defined. Is an “emergency” the same as a SOL exceedance or is it a SOL or IROL violation?

Organization	Yes or No	Question 7 Comment
		3. R10 requires that TOPs monitor adjacent TOP facilities as "needed to maintain reliability." This term is vague and needs defined parameters or criteria. 4. The data retention period for R13 is far too long, as the RTCA files are quite large (current calendar year + previous calendar year).
Response: (1) The SDT understands how one could view Requirements R16 and R17 as outage coordination. However, the SDT believes the outage coordination standard deals with BES Elements while Requirements R16 and R17 pertain to monitoring and analysis capabilities which more appropriately belong in a standard dealing with monitoring and operating in Real-time which is proposed TOP-001-3. No change made. (2) Emergency is already a NERC defined term. An SOL exceedance could qualify as an Emergency. An IROL violation or exceedance certainly would. However, other events such as a significant equipment overload (i.e., one that risks immediate failure of the equipment) could be an Emergency as well. Please refer to the definition. No change made. (3) The SDT has modified Requirement R10 to better reflect that it is only those neighboring Transmission Operator Facilities that impacts its own Transmission Operator Area. See summary consideration for revision. (4) Requirement R13 does not require RTCA. However, recognizing that many entities might utilize RTCA to meet the requirement, the SDT agrees and has modified the data retention to 30 days. See summary consideration for revision.		
Idaho Power	No	I do not agree with the rationale for the change in terms. There need to be something to differentiate between a communications that must be followed to alleviate existing or potential conditions to preserve system reliability. Operating instructions should be normal communication between a System Operator and field personnel during routine switching or system adjustments. A Reliability Directive is an order to do a task without hesitation unless it would violate safety, equipment, regulatory or statutory requirements. As currently written the standard would seem to apply to anything the RC requested a TOP to do. Reliability Directive is in the NERC glossary of terms currently.

Organization	Yes or No	Question 7 Comment
		The first sentence in R1 notes this when it states "or DIRECTS others". This change will create confusion resulting in adverse reliability impacts and compliance violations. I'm not clear on what R10 requires. Would we be required to monitor all our adjacent TOP's SPS and communication systems, facilities that the SPS monitored or just request a status point via ICCP form the adjacent? Needs to be clearer on what the requirement expects to be monitored.
Response: While the SDT agrees that Operating Instructions issued during Emergencies are very important, failure to follow an Operating Instruction issued during normal operating conditions can and has led to actual Emergencies. This was the case in the September 2011 Southwest Outage. The SDT disagrees that the Operating Instruction would apply to anything the Reliability Coordinator would ask a Transmission Operator to do. For instance, if a Reliability Coordinator requested the Transmission Operator to determine how quickly they could return a line to service that was out on maintenance, this would not be an Operating Instruction. While we agree Reliability Directive is in the NERC Glossary, it was never approved by FERC. No change made. The SDT is confused by the comment regarding "or DIRECTS others" in Requirement R1 and how it will create confusion resulting in Adverse Reliability Impacts and compliance violations. Transmission Operators provide instructions to "others" all the time. For example, when it issues a switching instruction, it communicates this to field personnel or possibly to a Distribution Provider that is connected to its transmission line. Without additional specificity, the SDT has no choice but to leave the requirement unchanged. The Transmission Operator would be required to ultimately monitor what impacts its Transmission Operator Area reliability. Changes have been made to Requirement R10 to provide clarification. See summary consideration for revision.		
David Kiguel	No	R7: How will the entity that requested assistance demonstrate and how will the entity whose assistance was requested verify that the requesting entity has implemented its emergency procedures? R10: Requires TOP to monitor facilities in neighboring TOP Areas, i.e. outside its own area of responsibility.

Organization	Yes or No	Question 7 Comment
		R11: How will the BA monitor SPS status i.e. who provides the information? Better to assign requirement action to the entity providing the information to the BA. This seems to be covered by TOP-003-3 R4, i.e. no need to repeat here.
Response: The requesting entity can simply notify the recipient that it implemented its emergency procedures. The recipient will have to depend on this simple notification or risk a compliance violation for not providing assistance. The observation on Requirement R10 is correct. The Transmission Operator needs to monitor only those the Facilities in its neighboring Transmission Operator Areas that impacts its own reliability. The requirement has been updated to reflect this. See summary consideration for revision. Proposed TOP-003-3 Requirement R4 provides a mechanism to receive the data on SPS status. Requirement R11 requires the Balancing Authority to actually monitor the status. No change made.		
Austin Energy	No	City of Austin dba Austin Energy (AE) supports the streamlining effort and removal of redundant requirements. However, AE offers the following comments on R1: (1) AE does not agree with the change to R1, which removes the "responsibility and clear decision-making authority" language from the previous standard. AE believes the authority language provides clarity and substance in an easily recognizable format. System Operators are familiar with the NERC Reliability Standards, but they are not as well versed in the specifics of FERC Orders, such as FERC Order 693a, paragraph 112. AE believes the remaining requirements in the TOP/IRO families instruct the TOP to "act, or direct others ... to act" while providing more specificity regarding such actions. In this way, R1, as proposed, is redundant and difficult to demonstrate from a compliance perspective given its general nature. AE recommends combining the old and new R1 language to state "Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed, including issuing Operating Instructions, to address its reliability functions within its Transmission Operator Area." (2) AE does not agree with R10, which requires monitoring "neighboring Transmission Operator Areas to maintain reliability." Without additional guidance, many TOPs will

Organization	Yes or No	Question 7 Comment
		be left with a requirement to monitor its neighbors' entire systems. The role of coordinating reliability is that of the Reliability Coordinator, as agreed by the SDT on the project's 6/12/14 webinar. During the webinar, the SDT stated the TOP should be aware of seams but it is the RC that has ultimate responsibility to ensure reliability across the seams. AE respectfully requests the SDT to review this issue further and refine the requirements accordingly. (3) AE believes R7 is not necessary as written. Assistance requested from one TOP to another is just that, a request. If it becomes an issue of reliability, the TOP would need to involve the RC who has other requirements in place allowing the RC to issue an Operating Instruction to the necessary TOP(s). AE requests the SDT remove R7 from TOP-001-3.
Response: (1) The SDT disagrees and believes that the replacement of the authority language with the action language is the correct approach. No change made. (2) The Transmission Operator would be required to ultimately monitor what impacts its Transmission Operator Area reliability. Changes have been made to requirement R10 to provide clarification. See summary consideration for revision. (3) The SDT disagrees that Requirement R7 is not necessary. Requirement R7 obligates Transmission Operators to work together to provide assistance during Emergencies. While the Reliability Coordinator likely will be involved, a directive from a Reliability Coordinator should not be necessary for a Transmission Operator to begin assisting another Transmission Operator. Some clarifying changes have been made to the requirement based on comments from others. See summary consideration for revision.		
Ameren	No	R3 - We operate as both a TO and BA. This change isn't really negative, but it always seems strange to us when we say that as a BA we comply with instructions issued by the TO, which is us. We believe that NERC should have clarifying language that it is more intuitive for entities that operate as a combined BA/TO, so that requirements that state that the BA follows instructions/directives from the TO (or vice versa) are not applicable. R4 - We are concerned because "BA" is in the list of entities required to follow directives issued by the TO. Our current RSAW says this is NA since it is only for DP's

Organization	Yes or No	Question 7 Comment
		and LSE's. Under the proposed draft with the BA listed in the requirement, we now have to state that as a BA, we follow directives given by the TO, which is also us, and in our opinion this doesn't make sense for the way we are organized. R6 - See my comments about BA's following instructions/directives from TO's as stated above. It also looks like they have new requirements stating that TO's will follow instructions issued by its BA. As stated earlier we have the same sort of comments, as for us, we are one in the same. R13 - We ask for clarification; does the drafting team mean running something automatically like the RTCA, this, conceptually, is OK, since we run it every 2 minutes. However if the drafting team means something else, we need to object, as we simply don't have manpower to perform manual studies every 30 minutes. The issue is, assuming the RTCA; would it be a reportable violation if the RTCA program goes down for longer than 30 minutes? We believe it would be a burden to ask entities to track and self-report instances where RTCA was down for 30 minutes or longer.

Response: The SDT appreciates the concern that faces many entities that operate as both a Balancing Authority and Transmission Operator. However, NERC decided to write the reliability standards requirements based on the functional model. These are two separate functional entities that can and are operated by separate companies in many areas. The SDT believes this is essentially a compliance monitoring issue. The SDT encourages you to work with your regional entity to address it. No change made.

The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability.

The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
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- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of “Real Time Assessment” does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking “alternative actions” and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator’s Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.

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<tr><td>Consumers Energy</td><td>No</td><td>

I am opposed to replacement of Reliability Directive with Operating Instruction. Reliability Directive is a much stronger term than Operating Instruction, and should be used in this context.

R5 and R6 - I generally agree, except for Reliability Directive vs. Operating Instruction as noted above. This should be Reliability Directive.

R9 - I am concerned about the general treatment of outages discussed in the requirement. It is not uncommon to experience frequent brief outages - requirement should have a “of duration greater than <some value, perhaps 15 minutes>“.

R10 - Individual TOPs may not be able to obtain monitoring access to adjacent TOP areas - this could create a compliance risk outside the entity’s control.

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Response: Failure to follow an Operating Instructions issued during normal operating conditions can and has led to actual Emergencies. This was the case in the September 2011 Southwest Outage. Thus, the SDT believes that the standard should apply to Operating Instructions and not just Reliability Directives. Furthermore, this make the standard consistent with proposed COM-002-4. No change made.

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Organization	Yes or No	Question 7 Comment
The SDT disagrees that a timing factor is needed in the requirement and believes that placing such a factor in the requirement may actually be detrimental to reliability. No change made. The SDT is not aware of any situations in which a Transmission Operator has not been able to gain data and information from neighboring Transmission Operators. No change made.		
Liberty Electric Power, LLC	No	See comment provided to the similar IRO standard.
Response: See response to IRO comments.		
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 negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment..."In response to R9, Oncor recommends that the requirement make it mandatory for RC's and TOP's to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it is necessary to notify registered entities that do not have reliability control functions to the BES. R10 as proposed requires each "Transmission Operator monitor facilities in neighboring Transmission Operator Areas in order to maintain reliability within its Transmission Operator Area". The 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 the 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. Oncor requests R10 be reworded to provide flexibility for region structure. 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

Organization	Yes or No	Question 7 Comment
		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. Proposed R13 states: "Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes." Oncor considers Real-time Assessments to be a Reliability Coordinator function. In the ERCOT region, Transmission Operators do not have the wide area overview that is required to perform the task. Requiring Transmission Operators to replicate Real-time Assessments currently performed by the Reliability Coordinator creates added expense and contributes no added reliability to the BES. Oncor requests R13 be reworded to provide flexibility for region structure.
Response: The SDT disagrees that the suggested change adds clarity. No change made. Data communications between the Transmission Operator, Balancing Authority, and Reliability Coordinator are bi-directional. Transmission Operators should work with the Reliability Coordinator to put processes in place to receive the external data required for reliability. The SDT does not believe this should be a financial burden. No change made. The T_v of an IROL is determined according to the Reliability Coordinator SOL methodology per approved FAC-014-2 Requirement R1. No change made. While the Reliability Coordinator does have responsibilities to monitor and assess reliability for its Wide Area, this does not remove the responsibility for the Transmission Operator to monitor and maintain reliability in its own Transmission Operator Area. No change made.		
ITC	No	ITC has concerns with the definition of "Real Time Assessment". Real time assessment is typically conducted by tools such as State Estimator and Contingency Analysis. Inclusion of known protection system and special protection system status or degradation is not practical or possible in real time simulations as these simulations are steady state analysis while studying protection system degradation requires a dynamic analysis. As suggested under comments on Operational Planning Analysis Definition, protection system degradations are studied when the outages on

Organization	Yes or No	Question 7 Comment
		protection system or associated elements are planned. Including this analysis in real time assessment may require dynamic simulations every thirty minutes which is not practically possible and provides no additional benefits. ITC supports that unplanned protection system outages impacting BES reliability shall be evaluated and appropriate action should be taken however conducting this evaluation as part of real time assessment shall not be required. ITC recommends modifying this definition by removing protection system and special protection system status or degradation. Regarding R10, ITC recommends adding clarification to this requirement clearly outlining that it is up to the TO to determine which external facilities to monitor based on impact to their internal system. ITC also recommends removing sub-100 kV language as a sub 100 kV element needed to maintain reliability of the system should already be designated as part of BES. In reference to R14, ITC would like clarification from the SDT as to whether the standard will include the methodology/examples listed in the SOL Exceedance White Paper.
Response: The SDT does not intend for a Real-time Assessment to include dynamic analysis. However, the SDT believes that the evaluation of Protection System outages and SPS outages can and should be assessed in steady state analysis. As an example, Contingencies could be modified to reflect an outage of the Protection System that may cause more Facilities to be cleared during a fault. No change made. The SDT agrees with your assessment and has modified Requirement R10 accordingly. See summary consideration for revision. The whitepaper will be appended to the standards.		
Hydro One	No	R-10 requires TOPs to monitor facilities in neighboring TOP areas and is an overlap of an RC wide area review responsibility.
Response: The SDT disagrees that monitoring facilities in neighboring Transmission Operator Areas is an overlap of the Reliability Coordinator Wide Area responsibility and believes it is necessary for Transmission Operator reliability. However, the SDT did modify		

Organization	Yes or No	Question 7 Comment
the requirement to reflect that it only needs to monitor the Facilities in neighboring Transmission Operator's Areas necessary to maintain reliability in its own Transmission Operator Area. See summary consideration for revision.		
Tri-State Generation and Transmission Association, Inc.	No	Tri-State believes R10 is confusing as it is written. We believe the portion stating "...including sub-100kV facilities needed to maintain reliability..." is redundant as "Facilities" is a defined term that includes any element that is part of the BES. With the new BES definition, elements may be included through the Rules of Procedure exception process if they are important to the reliability of the BES.
Response: The SDT has modified the requirement for clarity based on comments. See summary consideration for revision.		
Independent Electricity System Operator	No	We do not agree with Requirements R2, R5, R6, R7, R9, R11, R17 and R18. Requirement R2 stipulates that "Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area." This requirement seems out of place. Further it doesn't provide any incremental value since it is written at too high of a level and would be difficult to measure. The purpose of the standard is to ensure transmission operating reliability, not resource adequacy, balancing capability or frequency performance. The BA is not required to have any transmission information, and it does not have any sole responsibilities in ensuring transmission reliability other than responding to instructions by its TOP or RC to manage resource-demand-interchange balance or interchange schedules to assist in mitigating transmission constraints. With respect to implementing the IERP's and OC's recommendation to ensure BA has the authority to act or direct others to act, any such requirements (to maintain resource-demand-interchange balance or meet frequency performance targets) should be placed in the BAL standards or the EOP standards, but not in a TOP standard. We suggest R2 be removed. In addition, Requirements R5 and R6 should be removed as well. For Requirement R7, we do not see the need to include the Balancing Authority since it is supposed to comply with the Operating Instructions of its Transmission Operator

Organization	Yes or No	Question 7 Comment
		(in R3). We believe the proposed R7 is a revised version of R4 of TOP-001-2, which was approved by the NERC BoT in May 2012. Requirement R4 in TOP-001-2 did not include the BA as a responsible entity. We suggest to remove the BA from R7. Requirement R9 stipulates that: "Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities." The last part appears to be unclear as the "affected entities" can be interpreted as any two entities not including the one that is experiencing or anticipating outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. In that case, the entity that is held responsible for notifying others of its existing or anticipated outages will have no knowledge if the "associated communication channels between affected entities" will have an outage and if so, whether such an outage will negatively affect others. We suggest the last part be revised to "between it and the affected entities". Requirement R11 is out of place for the similar reasons indicated for R2, above. In addition the requirement seems inappropriate for the BA as it assigns transmission accountabilities which are not required in the Functional Model. We suggest removing this requirement. Requirement R17 is out of place for the similar reasons indicated for R2 and R11. We suggest moving this requirement to the appropriate BAL or EOP standard. Requirement R18 should not include the Balancing Authority since it does not operate any Facilities for which there are limits derived by more than one entity, unlike its TOP or RC counterpart.

Organization	Yes or No	Question 7 Comment
Response: The SDT ultimately agrees that Requirements R2, R5, R6, R11, and R17 belong in the BAL standards but there is no current active project that with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BA standards at a later date. No change made. The SDT agrees and has removed Balancing Authority from Requirement R7. See summary consideration for revision. The SDT has modified the requirement to provide additional clarity based on comments. See summary consideration for revision. The SDT disagrees that a Balancing Authority should not be included in Requirement R18. While a Balancing Authority may not derive limits, it certainly does operate to them in certain cases. No change made.		
INDN - Independence Power & Light	No	INDN supports the comments submitted by Southwest Power Pool. In addition R10 does not provide enough detail as to what the TOP's responsibility is. How far into a neighbor's facility are we required to monitor? At some point this should become the responsibility of the Reliability Coordinator, who has a much better regional view than individual TOPs. R13 attempts to make a "one size fits all" solution for performing Real Time Assessments. We believe this is too prescriptive and does not reflect a realistic approach to operations in some environments. For a TOP with no identified IROL or an entity that typically operates at low load levels it may not be necessary to perform a full assessment every 30 minutes. Small operations with minimal staffing will be unnecessarily burdened to perform, review and document assessments that add little or no Reliability benefit in these circumstances. A better approach may be to establish a threshold for system capacity or rate-of-change that would then trigger the 30 minute interval.
Response: The TOP would be required to ultimately monitor what impacts its Transmission Operator Area reliability. Changes have been made to Requirement R10 to provide clarification. See summary consideration for revision. The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the		

Organization	Yes or No	Question 7 Comment
current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.		
Modesto Irrigation District	No	MID believes that the implementation timeline for TOP-001-3 is not adequate to handle the business changes required by R13. MID suggests two years be allowed to implement R13.
Response: The SDT disagrees with the need to extend the implementation period to 24 months for Real-time Assessments. While they may not have been explicitly required, Real-time Assessments have always been necessary for a Transmission Operator. Transmission Operators are currently required to operate within all SOLs and IROLs. How can they do this without today performing a Real-time Assessment? No change made.		

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Electric Reliability Council of Texas, Inc.	No	Similar to comments provided for IRO-001 R1, ERCOT recommends maintaining existing TOP-001-1a R1 language as much as possible as follows: "Each Transmission Operator shall have clear decision-making authority to act and to direct actions to be taken by other entities to preserve the reliability of its Transmission Operator Area and shall exercise specific authority to prevent or mitigate operating emergencies without delay, but no longer than 30 minutes. [Violation Risk Factor: High][Time Horizon: Real-time Operations]". This would preserve the original purpose of the requirement, address NOPR paragraph 64, be consistent with IRO-001 R1, and provide a timeliness requirement where appropriate for all requirements that require action by a TOP in real time without redundancy. R2 should be applied consistent to these changes as well. For R14, the current definition of Operating Plan states "a document". Please refer to previous comments for IRO-008 related to this issue. Please refer to previously provided comments for IRO-001 related to the use of the defined term "Operating Instruction" outside of real time.
Response: The SDT disagrees and believes that the replacement of the authority language with the action language is the correct approach. No change made. Please see our comments to IRO-008 for Requirement R14. Please see our comments to IRO-001 regarding Operating Instruction.		
California ISO	No	The wording in proposed TOP-001 requirements R1 and R2 contains the following phrase: "by issuing Operating Instructions, to address its reliability functions". The term "reliability function" is not defined in the standard or in the NERC Glossary of Terms, especially as it applies to each individual entity (i.e., - "its reliability functions") and is therefore too vague and subject to interpretation. These requirements could possibly reference "reliability-related tasks" which are required to be defined by PER-005, however this might not be inclusive enough because there might be

Organization	Yes or No	Question 7 Comment
		unanticipated situations when an Operating Instruction is necessary to maintain reliability but isn’t related to a documented task. The ISO would propose changing this wording to something like “by issuing Operating Instructions, for reliability purposes” or “by issuing Operating Instructions, when necessary to maintain reliability”.
Response: The SDT has modified Requirements R1 and R2 for clarity based on comments. See summary consideration for revision.		
Texas Reliability Entity	No	1) R1: The use of the defined term “Transmission Operator Area” in R1 and R10 may lead to potential conflicts and reliability gaps. Transmission Operator Area is defined in the NERC glossary as "The collection of Transmission assets over which the Transmission Operator is responsible for operating." Transmission is capitalized indicating the following NERC glossary definition, "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Using these definitions in the requirements may create a reliability gap if a TOP determines that generation, LSEs or DPs are not included in the Transmission Operator Area because they don't meet the definition of Transmission. In the ERCOT region where we have had TOP entities make the argument that generation units are not in their Transmission Operator Area and therefore they were not required to monitor those facilities. Similarly, it could be argued that ERCOT as a TOP does not "operate" any transmission assets. In the ERCOT region, a Coordinated Functional Registration is required between ERCOT and 15+ utilities to clarify the responsibilities of the TOP Function. Would the SDT consider adding technical guidance to clarify the entity functions that are considered part of a Transmission Operator Area. Clearly, R3 requires BAs, GOPs, DPs and LSEs to comply with Operating Instructions issued by its TOP but there appears to be a risk that a TOP may not issue an Operating Instruction to an entity they do not consider within their Transmission Operator Area due to the definition.

Organization	Yes or No	Question 7 Comment
		2) R4: Recommend adding the following additional language behind the sentence in R4: "The instructed Entity will inform the TOP within 30 minutes of determining that it would not be able to or failed to carry out the Operating Instruction." If an Operating Instruction cannot be followed by the instructed entity, the TOP needs to be informed of the situation in time for the TOP to react accordingly for the continued reliability of the BPS. Adding the stated time horizon will add another measure to R4. 3) R6: Recommend adding the following language at the end of the Requirement: "citing one of the specific reasons shown in Requirement R5." This will be consistent with R4 referencing R3. 4) R8: Recommend adding the following language at the end of the Requirement: "The TOP shall inform the Entities of these issues within 30 minutes of determining that its actual or expected operations that result in, or could result in, an Emergency." The purpose of the standard is to ensure prompt action to prevent or mitigate adverse impacts to reliability. As such, communication of actions taken or expected actions that may result in and emergency should be communicated before that emergency occurs. As written the TOP could be compliant by informing the Entities well after the potential or actual emergency has occurred. 5) R9: Recommend adding "within 30 minutes" between "shall notify" and "its Reliability Coordinator". This will help assure that notified entities will have time to appropriately respond. The purpose of the standard is to ensure prompt action to prevent or mitigate adverse impacts to reliability. R9 has no stated time horizon for notification. As written the BA and TOP could be compliant by informing the RC (and other impacted interconnected entities) well after the potential or actual emergency has occurred. 6) R9: Recommend excluding "negatively" and "interconnected" and simplifying to "impacted" entities to be consistent with TOP-002-4 language. And to reflect that

Organization	Yes or No	Question 7 Comment
		entities that are not “interconnected” can be impacted by outages of the equipment mentioned in R9. 7) R15: Recommend adding "within 30 minutes of having completed actions, provided the TOP is capable of reporting the actions" between "shall" and "inform its Reliability Coordinator". The purpose of the standard is to ensure prompt action to prevent or mitigate adverse impacts to reliability. As such, the RC must have up to date information concerning actions taken within its area to perform its reliability responsibilities.
Response: (1) The SDT has modified Requirement R1 to clarify that it includes entities connected to its Transmission Operator Area. The SDT does not see a similar issue with Requirement R10 and has not modified it based on this comment. (2), (4), and (7) The SDT does not agree with adding 30 minutes to Requirements R4, R8, and R15. There are times when a 30-minute notification would be sufficient and other times it would not be (i.e., when exceeding a 15-minute limit) and could impact reliability. While adding this term would make it more measurable for compliance, it could be contrary to reliability. Each situation is unique regarding how quickly a receiving entity should notify the issue of its inability to follow an Operating Instruction but it should be quickly. No change made. (3) The SDT disagrees with the addition to Requirement R6 and actually is removing the “citing” language in Requirement R4 due to other comments. At the time an entity notifies the Transmission Operator or Balancing Authority that it cannot implement an Operating Instruction, the reason is not nearly as important as the fact they can’t and alternative actions are necessary. Why and whether it was a valid reason can be sorted out later. The receiver of the Operating Instruction may not have time in Real-time to figure out which one of the reasons in the requirement is the correct and valid reason. No change made. The SDT disagrees with the addition of the 30-minute time constraint as described above and believes that it may actually be detrimental to reliability. No change made. (6) The SDT has modified Requirement R9 to remove negatively. The SDT disagrees with removing “interconnected” as it believes that this requirement only need apply to immediate neighbors. No change made.		
Georgia Transmission Corporation	No	(1) Purpose: Since Operating Instructions are specific to the operation of the interconnected Bulk Electric System, GTC believes the purpose statement should be revised to be consistent with the terms being utilized and to be consistent with other

Organization	Yes or No	Question 7 Comment
		Standards closely associated such as COM-002-4. Specifically GTC recommends replacing the terms “reliability of the Interconnection” with the terms “reliability of the Bulk Electric System (BES)”. (2) The current proposal for R3 and R5 as written could overly expose the DP and LSE excess compliance obligations for routine switching operations performed on a daily basis which does not affect the reliability of the BES such as maintenance items, etc. The DP and LSE implement operating instructions on non-BES equipment on a routine basis, but the implementation of operating instructions on BES equipment, or non-BES equipment “affecting the reliability of the BES” is not very routine. GTC believes the intent of this requirement for the DP/LSE should complement COM-002-4 R6 relating to Operating Instructions during an Emergency “affecting the reliability of the BES”. The use of the NERC term “Emergency” would capture this intent. GTC proposes the language “[during an Emergency]” be added after “....shall comply with each Operating Instruction issued by its Transmission Operator(s) [during an Emergency] “.
Response: (1) The SDT agrees and has modified the purpose statement. See summary consideration for revision. (2) The SDT disagrees that Requirements R3 and R5 should only apply in Emergencies as failure to properly implement an Operating Instruction could be the initiating action the leads to an Emergency. This was the case in the September 2011 Southwest Outage. However, in response to other comments, the SDT has modified Requirements R1 and R2 to reflect that these are Operating Instructions issued to preserve reliability on the BES. See summary consideration for revision.		
NV Energy and MidAmerican Energy	No	R1 and R2: The requirement to act or direct others by issuing Operating Instructions calls into question the ability of a TOP or BA to demonstrate in all cases that Operating Instructions were issued. Would this require the logging and retention of records for each and every Operating Instruction given by a TOP or BA? If so, the volume could easily exceed hundreds of documented Operating Instruction exchanges per day. Also, we recommend changing the phrase “to address its

Organization	Yes or No	Question 7 Comment
		reliability functions" to "to maintain system reliability", as this is more precise and descriptive of the rationale for action. R3 and R5: We note that pending the final definition of Operating Instruction, there may be a significant number of Operating Instructions for which an entity will be required to maintain documentation. R7: The term "assist" is used in describing the required action in response to a requestor. This term is sufficiently vague and ambiguous; therefore, we suggest the use of examples or parameters be provided around the term "assist" in order to clarify the intent and scope of the assistance. Perhaps add clarifiers like "such as delivery of energy, adjustment of reactive power supply or absorption, use of controllable devices, etc." R10: This requires the monitoring of facilities within its TOP area and neighboring TOP areas, including sub-100 kV facilities needed to maintain reliability and the SPS within its TOP area. This reaches prescriptively into the realm of the neighboring TOP's without specifying the degree of monitoring required or whether this is limited to immediately adjacent TOP's or all TOP's "in the neighborhood". I would suggest limitations be placed on the scope of this requirement, as it significantly expands the monitoring task and the demonstration of compliance, and worse, it runs the risk of causing the TOP to lose focus on his own operating area. While there is some merit in operator view into adjacent systems, the wide area view suggested by this requirement is more applicable to the functions of an RC. R9: Recommend that R9 read as: "Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and (removed negatively) potentially impacted interconnected NERC registered entities of forced outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between such entities." R13: The requirement to perform a Real-Time Assessment once every 30 minutes is onerous and goes beyond the directive findings of the SW outage event.

Organization	Yes or No	Question 7 Comment
		Recommend the use of a performance-based requirement rather than a rigid requirement to conduct at least 48 assessments each day. The goal ought to be that the Operator is continuously aware of the impact of any contingency upon the system, not that the assessment is performed on a 30 minute basis. What allowance is provided for loss of contingency analysis tools? Such loss is a reportable event, yet under this requirement it also becomes a violation if not restored and satisfactorily executed within 30 minutes. R14: This requirement compels the TOP to initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-Time Assessment or real time monitoring. The requirement is unacceptably open-ended and does not specify the time frame for such initiation, or even what it means to “initiate” its plan. We suggest specificity be added by the SDT in the text of this requirement. R15: The requirement to “inform” the RC of actions to return the system to within limits also lacks specificity as to the time frame to inform, and the allowable means to inform. As well, it is left to interpretation whether the "actions to return the system to within limits" are those that have been taken or those that will, or could be, taken. We suggest clarification of intent on this requirement and the allowance that electronic SCADA information will satisfy the duty to inform. R16 and R17: The authority to approve does not literally mean that the BA/TOP Operator “must” approve; therefore, there may be an unintended consequence that such maintenance work could be performed without BA or TOP approval. If the intent of the SDT is not met here, clarification is necessary to ensure that all such work must first be approved by the BA/TOP Operator.
Response: The SDT does not believe it will be necessary to retain all data associated with all issuances of Operating Instructions and the compliance could be demonstrated with internal controls such as a procedure and supporting evidence (i.e., recent examples of Operating Instructions) that such a procedure was followed but ultimately this will be up to registered entities to determine how to comply. The SDT has modified Requirements R1 and R2 consistent with your recommendation. See summary consideration for revision.		

Organization	Yes or No	Question 7 Comment
The SDT does not believe that the term assist should be defined through enumeration as there could be many ways that a Transmission Operator could provide assistance. During an Emergency, the SDT does not want to limit the options. No change made. Ultimately, it will be up to the Transmission Operator to determine how much of its neighboring Transmission Operators system it needs to monitor maintain its own Transmission Operator Area reliability. Some clarifying changes have been made to the requirement to assist with this understanding. See summary consideration for revision. The SDT has removed “negatively” from Requirement R9 but it not adding “forced”. Ultimately, it is important to report the outage regardless of whether it was planned or unplanned. Other additional clarifying changes have been made in response to other comments. The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity’s Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of “Real Time Assessment” does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking “alternative actions” and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator’s Contingency analysis results when their capabilities are unavailable and vice-versa. The		

Organization	Yes or No	Question 7 Comment
SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. The SDT does not believe additional specificity is needed for Requirement R14 and believes putting a timeframe on the requirement may be contrary to reliability. Not all SOLs will require the same time response. No change made. The purpose of Requirement R15 is to notify the Reliability Coordinator that the SOL has been or is being addressed so that the Reliability Coordinator is not also simultaneously issuing conflicting actions. Notification of the Reliability Coordinator before taking actions or after taking actions may be dependent on the unique situation. Thus, the SDT does believe the requirement is as clear as it can be. No change made. The SDT does not agree that authority to approve comes with the option of whether to exercise that authority and believes failure to exercise the authority would be a violation of Requirements R16 and R17. No change made.		
FirstEnergy	Yes	While FirstEnergy generally supports TOP-001-3, we have concern with 30 minutes time frame for updates on Real Time Assessments. This obligation contradicts the 2 hour time frame set in EOP-008. Also, if there is a loss of data communications and there is a need to man substations; it may take longer than 30 min to stage personnel in the field.
Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.		

Organization	Yes or No	Question 7 Comment
· **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of “Real Time Assessment” does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking “alternative actions” and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator’s Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.		
Peak Reliability	Yes	o R1, R2: There is a potential conflict arising between a BA and TOP (when the two are not the same company) where a TOP may issue an Operating Instruction to a BA to shed load or bring up generation and at the same time a BA may issue a directive to the TOP to trip/restore a line for potentially the same reliability issue. Will both be required to follow each other’s directives? o R10: The way it is phrased gives risk for misunderstanding. Is the Requirement that TOP must “monitor” the status of RAS? Or is the Requirement that the TOP must understand/model the impact of the RAS so that TOPs know the status of any SOL or IROL and whether or not it is being exceeded given the expected RAS action? The way it reads it seems the TOP is only required to “monitor” the RAS, which to Peak means have awareness of the arming status and know when the RAS operates. Also, this Requirement is unclear whether the TOP needs to monitor facilities in adjacent TOPs only to the extent that such facilities actually affect SOLs/IROLs? Adding the phrase “as needed” to “and neighboring Transmission Operator Area” adds more clarity.

Organization	Yes or No	Question 7 Comment
		o R11: "including the status of Special Protection Systems" should be "including the status and impact of Special Protection Systems"
Response: The Balancing Authority and Transmission Operator should be consulting one another when issuing Operating Instructions. However, in the event that there is a conflict in the Operating Instructions, the recipient can use the clause "unless such action… would violate… regulatory…" in Requirements R3 and R5. Both requirements will be regulatory requirements once approved by FERC. Transmission Operators and Balancing Authorities requiring the same entity to take conflicting actions in an Operating Instruction would clearly qualify as a violation of regulatory requirements. No change made. In Requirement R10, the requirement is to monitor the status of the SPS/RAS. The impact of the SPS and RAS will be assessed in the Real-Time Assessment in Requirement R13. The SDT does not believe adding "impact" to Requirement R11 provides any more clarification. Requirement R11 already states the purpose is to ensure that the Balancing Authority is able to perform its reliability functions. It can't do this without understanding the impact of the SPS/RAS. No change made.		
Volkmann Consulting	Yes	See comments on the SOL Exceedance document
Response: See response to SOL Exceedance Document comments.		
Xcel Energy	Yes	Xcel Energy agrees with the proposed changes overall. However, we would like to note that R3 requires entities to comply with Operating Instructions given by the TOP, while in R5 they are to comply with instructions of the BA Operator. We would like to see clarification added in the event that the operating instructions from the TOP and BA contradict each other. Additionally, R10 and R11 both reference Special Protection Systems. We would like to ensure this reference syncs up with the efforts of Project 2010-05.2 regarding the SPS/RAS Definition.
Response: The Balancing Authority and Transmission Operator should be consulting one another when issuing Operating Instructions. However, in the event that there is a conflict in the Operating Instructions, the recipient can use the clause "unless such action… would violate… regulatory" in R3 and R5. Both requirements will be regulatory requirements once approved by FERC.		

Organization	Yes or No	Question 7 Comment
Transmission Operators and Balancing Authorities requiring the same entity to take conflicting actions in an Operating Instruction would clearly qualify as a violation of regulatory requirements. No change made. The SDT is making every effort to sync up with all approved projects and definitions.		
ReliabilityFirst	Yes	ReliabilityFirst submits the following comments for consideration:1. Requirement R4 - ReliabilityFirst recommends 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 time frame, the reliability of the BES may be compromised if an Entity cannot perform the Operating Instruction in a timely manner. ReliabilityFirst suggests the following language for consideration. ”Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within 30 minutes of receiving an Operating Instruction] of its inability to perform an Operating Instruction issued by its Transmission Operator...” 2. Requirement R6 - ReliabilityFirst recommends adding a timeframe to the requirement limiting the time the Entity has to inform its Balancing Authority of its inability to perform an Operating Instruction. Absent a time frame, the reliability of the BES may be compromised if an Entity cannot perform an Operating Instruction in a timely manner. ReliabilityFirst suggests the following language for consideration. "Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within 30 minutes of receiving an Operating Instruction] of its inability to perform an Operating Instruction issued by that Balancing Authority.”
Response: The SDT does not agree with adding 30-minutes to Requirements R4 and R6. There are times when a 30-minute notification would be sufficient and other times it would not be (i.e., when exceeding a 15-minute limit) and could impact reliability. While adding this term would make it more measurable for compliance, it could be contrary to reliability. Each situation is unique regarding how quickly a receiving entity should notify the issue of its inability to follow a directive but it should be quickly. No change made.		

Organization	Yes or No	Question 7 Comment
PJM Interconnection	Yes	PJM does support the standard. We recommend the drafting team use only the term, 'Facility Rating' and not use the term 'derived limit.' This will provide for consistency is use of one term.
Response: The SDT has replaced 'derived limit' with 'SOLs' for clarity. See summary consideration for revision.		
PNMR	Yes	
Manitoba Hydro	Yes	
EDP Renewables North America LLC	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
Response: Thank you for your response.		

8. **Do you agree with the changes made to proposed TOP-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has responded to numerous requests for clarification and has made the following changes based on industry comments:

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

R3. Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

R5. Each Balancing Authority shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s).

Data retention: Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90 calendar days period for analyses, the most recent 90 calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	No	To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and change "compliance investigations" to "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes.
Response: Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure.		

Organization	Yes or No	Question 8 Comment
Associated Electric Cooperative, Inc. - JRO00088	No	FOR: TOP-002-4, draft 1 clean, general COMMENT: AECI supports comments posted by the SERC OC Work Group FOR: TOP-001-3 draft 1 clean, definition of Operational Planning Analysis COMMENT: AECI strongly favors the parenthetical sentence that appears as the last sentence within this definition, and believe it can help smaller Responsible Entities to avoid unnecessary cost of compliance where Operational Planning Analysis are required. COMMENT: We recommend the Operational Planning Analysis definitions include the following change: ‘The assessment may reflect inputs including, but not limited to: load, generation output levels,...’ RATIONALE: Inputs in the currently proposed definition are not applicable to all situations where assessments and analysis are needed. Usage of “may” provides recommendation for inputs that are valuable in some situations (and are currently used when applicable), however it does not require these inputs for every assessment, which creates an unneeded burden. FOR: TOP-002-4, draft 1 clean, Requirement R2 and Measurement M2REPLACE: (R2) “an Operating Plan(s)” and (M2) “an Operating Plan” WITH: “one or more Operating Plan(s)”RATIONALE: Grammar FOR: TOP-002-4, draft 1 clean, Requirements and Measurements, R4, M4, R5, M5, R7 and M7COMMENT: These Requirements for BAs really should reside within the BAL Standards.

Response: See responses to SERC comments.

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

The SDT does not believe this suggestion is necessary as it is implicit that more than one Operating Plan can exist. No change made.

The SDT ultimately agrees that these requirements belong in the BAL standards but there is no current active project with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made.

Organization	Yes or No	Question 8 Comment
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	Definition for Operational Planning Analysis: Delete the parenthetical. This does not clarify what the analysis is. At a minimum replace the word “contracted” with “arranged”. R2 - What are the circumstances for using an Operating Procedure vs an Operating Process? R4.4 - Clarify the use of “Capacity and energy reserve requirements, including deliverability capability “. Are these reliability based terms or commercial? R5 - Please clarify the use of the term “impacted”. Does this refer to normal operations or is it intended to capture exceptions to the normal operations? R6 - The amount of documentation would be very burdensome. R7 - The amount of documentation would be very burdensome.
Response: The SDT agrees and has revised the definition based on your comment and those of others to address this concern. See summary consideration for revision. R2-The Operating Procedure and Operating Process are both NERC defined terms. The Operating Process is a document that identifies general steps for achieving a generic operating goal, while an Operating Procedure is a document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). R4.4: The terms are reliability-based and consistent with the terms used in approved TOP-002-2.1b Requirements R5 and R7. No change made. R5: The SDT believes that under all circumstances, if your plan requires actions on the part of another entity, or that its plan would cause a change that would affect the other entity then you need to communicate their responsibilities. No change made. R6 & R7: The SDT does not believe that this information sharing is overly burdensome and is necessary for the Reliability Coordinator to develop a coordinated plan. No change made.		
MRO NERC Standards Review Forum	No	R5 requires Operating Plans for each component of R4. Note that Operating Plans is defined as a DOCUMENT that identifies a group of activities...

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 8 Comment</th></tr>
<tr><td></td><td></td><td>Plus the notification of NERC Registered Entities identified in those plans. The NSRF does not know how, for instance, how having a requirement to inform someone of an Interchange schedule, that they established with you, how this promotes system reliability. Having a day ahead Operating Plan should assist the BA in tomorrow's operations. But notifying impacted NERC registered entities is not conducive. PJM, SPP, MISO, etc. are registered BAs and they would be required to have a (DOCUMENTED) Operating Plan every day that will restate generation resource commitments demand patterns and reserve requirements.

R5 should be deleted since the IERP only recommends this and it is not a FERC directive.</td></tr>
<tr><td colspan="3">Response: The SDT believes that Requirement R5 as written does not require a separate Operating Plan for each component of Requirement R4.

The SDT does not believe that Requirement R5 requires notification to all entities that provide the Balancing Authority with information but rather takes the inputs from those entities and develops a plan to fulfill the Balancing Authority obligations as defined in the Functional Model. No change made.

The SDT believes this requirement is consistent with approved TOP-002-2 Requirement R7 and is supported by the Southwest Outage Report Recommendations along with the recommendation from the IERP. No change made.</td></tr>
<tr><td>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</td><td>No</td><td>R4 - Southern suggests that sub requirements, 4.1, 4.2, 4.3 and 4.4 are vague in nature and should be more descriptive by defining specific expectations of what should be addressed. Example: R4.2 as written is unclear as to whether the BAs Operating Plan is expected to address making, accommodating, curtailing, ramping of interchange schedules, etc.

R4 and R5 and R7 - It is unclear on what actions would be included in the BA Operating Plan. In the case of the TOP, it is very clear in that the Operating Plan is to address potential SOLs. The R4 subparts include data provided to the BA for reserves planning purposes from other entities. The BA should not be required to notify all</td></tr>
</table>

Organization	Yes or No	Question 8 Comment
Georgia System Operations Georgia Transmission Corporation		entities and provide them with the very information those entities provided to the BA as seems to be required in R5. R6 and R7 - Southern suggest that a periodicity for providing data and a deadline by which the respondent is to provide the indicated data should be applied to these requirements to be consistent with corresponding RC requirements, R1.3 and R1.4 in proposed IRO-010-2 Reliability Coordinator Data Specification and Collection.
Response: The SDT believes the proposed language is clear, is consistent with the terms used in approved TOP-002-2.1b Requirements R5 and R7. No change made. R4, R5, and R7: The SDT does not believe that Requirement R5 requires notification to all entities that provide the Balancing Authority with information but rather takes the inputs from those entities and develops a plan to fulfill the Balancing Authority obligations as defined in the Functional Model. No change made. R6 and R7: The SDT believes that the documented specification for the data identified in proposed IRO-010-2 will clarify periodicity and deadline issues and therefore that they don't need to be repeated here. No change made.		
Dominion	No	While Dominion agrees conceptually with Requirements 4 and 5 we do not believe they belong in the TOP family of standards.
Response: The SDT ultimately agrees that these requirements belong in the BAL standards but there is no current active project with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, FMPA believes R1 should refer to the performance requirements of FAC-011 R2 or specify "in accordance with its SOL Methodology" so that the breadth of contingencies to be studied is known.
Response: See response to FRCC.		

Organization	Yes or No	Question 8 Comment
The SDT believes the requirement as written is clear. Further the SDT believes that not exceeding any of "Its" limits would require that the entity would have its ratings set by their SOL methodology in conformance with current NERC standards. No change made.		
Duke Energy	No	R1-R3: No comments R4: Duke Energy suggests using alternative language in sub-part 4.4. Currently 4.4 states: We believe the language used is too broad, and could be open to interpretation. We recommend a re-wording to the following:"4.4: Contingency Reserve requirement obligations" This re-wording should reduce any unintended incorrect interpretations. Also, the removal of "deliverability capability" is necessary, as we feel that having the capability to deliver reserve requirements is inherent to the very nature of having Contingency Reserve obligations. R5: Duke Energy suggest using another term other than NERC registered entities. We suggest identifying those entities, per the Functional Model, that specifically interface with the TOP or use the term "Applicable entity". R6: Duke Energy believes that the amount of documentation needed to be retained for this requirement would become very burdensome to the TOP and RC. In addition, the proposed IRO-008-2 requires the RC to coordinate Operating Plans amongst its TOP and BA and this appears to be redundant. Additional concerns we have with this requirement is that there does not appear to be a stipulation for submitting an updated plan, if conditions were to change. For example, an Interchange Schedule is subject to change multiple times. Ultimately, we feel that the RC should have a next day Operating Plan in place to acquire the data necessary for the RC to perform their Operational Planning Analysis, the TOP/BA should then be obligated to follow that plan. We don't agree that a daily document is warranted. R7: See R6 comment. In addition, we believe this requirement belongs in the BAL family of standards.

Organization	Yes or No	Question 8 Comment
Response: R4.4: The SDT believes that Requirement R4, Part 4.4 conforms with approved TOP-002-2.1b Requirement R7 which states: Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency. Therefore this is not new terminology and the industry has been correctly interpreting the language. No change made. R5: The SDT agrees and has made the suggested changes**.** See summary consideration for revision. R6 and R7: Proposed TOP-002-4 Requirement R6 requires the Transmission Operator to share its Operating Plan with the Reliability Coordinator whereas proposed IRO-008-2 Requirement R2 requires the Reliability Coordinator to review the plans. Therefore Requirement R6 is not redundant. The SDT further believes that the information shared in Requirement R6 is necessary for the Reliability Coordinator to develop its coordinated plan. No change made.		
Bureau of Reclamation	No	Reclamation suggests that R3 should list the applicable "impacted NERC registered entities" that must be notified when they have roles described in Operating Plans (e.g., Generator Operators, Distribution Providers, etc.).
Response: The SDT believes that the Operating Plan referenced in Requirement R2 identifies which entities need to be notified. No change made.		
SPP Standards Review Group	No	Please see our comment on the definitions of Real-time Assessment and Operational Planning Assessment in Question 7. We suggest modifying Measure M4 to read: 'Each Balancing Authority shall have evidence that it has developed a plan that incorporated the criteria identified in Requirement R4. Such evidence could include but is not limited to dated operator logs or e-mail records.'
Response: Please see response to Q7. The SDT does not believe that the suggested change adds any additional clarity. No change made.		
ACES Standards Collaborators	No	(1) Requirements R2, R3, R6 could be combined with R1. There is overlap within these requirements and the notification requirements are vague.

Organization	Yes or No	Question 8 Comment
		(2) Requirements R4, R7 and R5 could also be combined. There is overlap within these requirements and the notification requirements are vague.
Response: (1) In general, Requirement R2 requires an Operating Plan, Requirement R3 requires notifying affected neighbors, and Requirement R6 requires sharing the Operating Plan with the Reliability Coordinator. The SDT believes that each of these requirements are substantive and necessary as separate requirements. No change made. (2) In general, Requirement R4 requires an Operating Plan, Requirement R5 requires notifying affected neighbors, and Requirement R7 requires sharing the Operating Plan with the Reliability Coordinator. The SDT believes that each of these requirements are substantive and necessary as separate requirements. No change made.		
ISO/RTO Standards Review Committee (SRC)	No	Requirements 6 and 7 are not results-based. We encourage NERC SDTs to focus on developing results-based standards.
Response: The SDT believes that Requirements R6 and R7 are measurable and necessary for system reliability and are results-based. No change made.		
Bonneville Power Administration	No	Concerning R1, BPA suggests clarifying the conditions under which an entity is required to assess whether planned operations will exceed any of its SOLs. Without this clarification, it is unclear whether R1 requires assessing normal system conditions: N-1 or N-1-1. Regarding R4, BPA feels that, because of the time and effort needed for forecasting and analyzing all items included in its sub-requirements, the inclusion of R4.1 and R4.2, which are market-driven, leave insufficient time to complete an adequate assessment for the next day. BPA believes the Standard would be better supported should the word “addresses” be replaced with “considers.” BPA also suggests that the “evidence” mentioned in M4 is ambiguous and suggests rewording M4 to state, “Each Balancing Authority shall have evidence that it has developed a plan to operate to the safe and reliable operation of the BES.”

Organization	Yes or No	Question 8 Comment
Response: R1: The SDT has developed a whitepaper regarding SOL identification that addresses your concern. No change made. R4: The SDT believes the proposed language is clear, is consistent with the terms used in approved TOP-002-2.1b Requirements R5 and R7, and is not solely market-oriented. No change made. The SDT does not believe that the suggested change adds any clarity and actually may cause confusion. No change made.		
CenterPoint Energy Houston Electric LLC.	No	CenterPoint Energy believes that some of the items in the proposed definition of Operational Planning Analysis are redundant. CenterPoint Energy recommends removing “known Protection System and Special Protection System status or degradation” as well as “equipment limitations” as these would be encompassed in Transmission outages, generator outages, and Facility Ratings and do not need to be identified separately. CenterPoint Energy also feels “identified phase angle limitations” are not applicable in all Regions and should be addressed under Section D, Regional Variances.
Response: The SDT believes the current verbiage is necessary and clarifies the requirements. No change made. The SDT agrees with the applicability of the phase angle limitations and included the term “identified” in the definition. If none are identified then none need to be addressed. No change made.		
City of Garland	No	Requirement 1Concern There is no provision for small Transmission Operators who’s Area (number / size of Facilities) is too small to financially justify installing this capability - all TOPs are not created equal.
Response: The SDT believes that an Operational Planning Analysis is required for developing an effective Operating Plan. The proposed definition actually accommodates smaller entities by allowing for 3rd-party handling of the task. No change made.		
American Transmission Company	No	ATC requests that the SDT consider the following recommended modifications: a. To be consistent in regards to terminology used in the Standards, ATC suggests that “Operational Planning Analysis” be renamed “Operational Planning Assessment”

Organization	Yes or No	Question 8 Comment
		similar to the term “Real-time Assessment.” For consistency, ATC suggests that this change be made throughout the proposed draft of Standard TOP-002-4. b. Operational Planning Analysis definition - ATC suggests the following changes to the definition for added clarity. Modify the first sentence of the definition by adding the word “single” to read, “An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-single Contingency) for next-day operations.” Otherwise, ATC suggests adding a sentence to the proposed definition to read, “Contingency conditions are limited to the most severe single contingency and the multiple outages specified by its Reliability Coordinator.” c. ATC requests the SDT to clarify the inconsistency between the use of “Operating Plan” in requirements R2 and R3 of TOP-002-4 with the explanation of this term in the “Rationale for Requirement R14” box within the draft TOP-001-3 standard. Specifically, the “Rationale for Requirement R14” explanation states that the “Operating Plan” is a single, general plan and philosophy for dealing with SOL exceedances. However, R2 and R3 of TOP-002-4 refer to the “Operating Plan” as a specific SOL exceedance plan with clearly identified actions by specific NERC registered entities. It is unclear if the TOP is to understand that the Operating Plan is a general philosophy or specific individual plans for each SOL exceedance identified during the next-day assessment. The companion white paper will not be part of the standard so clarity within the standards is important.
Response: The SDT does not believe that the suggested change provides additional clarity. The terminology has been in place for some time now and the industry is familiar with it and it might actually cause confusion to change it at this time. No change made. The SDT does not believe that the change is technically correct as single implies one item and there are instances where entities handle certain select multiple Contingencies as single Contingencies in analysis. No change made. The SDT believes that there is consistency in the use of the current defined term Operating Plan and the explanation in the Rationale Box. While an Operating Plan may contain Operating Procedures and Operating Processes, it may also simply identify a group of activities that may be used to achieve some goal. The companion whitepaper will be appended to the standard. No change made.		

Organization	Yes or No	Question 8 Comment
American Electric Power	No	R3: If a NERC registered entity is included in an Operating Plan, there is no need to use the word "impacted" as it could add confusion. This word should be removed.
Response: Proposed TOP-002-4 Requirement R3 is specific to those entities which play a role in the implementation of an Operating Plan, however it is possible that other entities identified in the plan play a role but are not impacted. No change made.		
NIPSCO	No	The data retention period required for the analysis is a rolling (6) months, as opposed to the prior data retention period of 90 days (TOP-002 R11). This time frame is too long and needs to be revisited unless there is a valid concern for holding 6 months of analysis.
Response: The SDT agrees and has made the suggested change. See summary consideration for revision.		
Idaho Power	No	I do not agree with this standard as written. The definition of Operational Planning Analysis would seem to require a TOP to have or contract Real-Time Contingency Analysis (RTCA) and all the required inputs. The definition does not specify what area should be modeled. It would seem that an entity could only model their internal system with their local inputs and be in compliance with this standard. If you are going to mandate RTCA there should be some expectation that external systems be modeled to some extent to better reflect actual conditions. As shown in the Southwest outage only looking at the extents of your system is not adequate.
Response: The proposed Operational Planning Analysis definition requires an evaluation of projected system conditions and does not necessitate the use of an RTCA or any other specific tool. No change made. Requirement R1 defines the area of responsibility as the Transmission Operator Area. The SDT believes in order to study your area for SOLs you have to expand your model to beyond the Transmission Operator Area borders. Proposed TOP-003-3 requires Transmission Operators to look outside its borders into external systems. No change made.		

Organization	Yes or No	Question 8 Comment
David Kiguel	No	R3 and R5: Notification requirement should be extended to all impacted entities, regardless of NERC registration. In some jurisdictions, e.g. Province of Ontario, NERC registration is not required for entities other than the IESO. Same may be possibly valid for other Canadian Provinces.
Response: The SDT agrees with the recommendation and has made the suggested change. See summary consideration for revision.		
ITC	No	In regards to the definition of "Operational Planning Analysis", ITC has concerns that the definition is too prescriptive in specifying required inputs for Next Day Analysis. Specifically, protection system and associated element outages are studied sometime several days ahead using relay clearing time and stability studies. These studies cannot be conducted daily for next day operations as the studies are time intensive and may require dynamic simulation. ITC is fully supportive of studying protection system outages and ensuring that these outages do not reduce the reliability of BES. However the definition should not restrict next day analysis to analyze these outages. Next day analysis is a steady state analysis conducted to ensure that system can operate reliably under all known contingencies. Including protection system outages in next day analysis will require dynamic simulation which is very different than steady state analysis, is very time consuming and does not provide additional value if such analysis has already been conducted when the protection system outage was planned. An alternate and more practical method is to include any potential over trip scenarios due to protections system degradations as these can be simulated by steady state analysis for next day conditions. The definition should be modified to allow the evaluation of protection system status or degradation analysis in the horizon deemed appropriate by the TOP.
Response: The SDT agrees that the Operational Planning Analysis includes a steady state analysis conducted to ensure that the system can operate reliably under all known Contingencies. The Operational Planning Analysis does not require a dynamic simulation each day, but rather that the results of those studies along with any status or degradation of those systems need to be considered in the Operating Planning Analysis. No change made.		

Organization	Yes or No	Question 8 Comment
Lincoln Electric System	No	As currently drafted, R6 would require the Transmission Operator to provide its Operating Plan to the Reliability Coordinator every day (next day studies) regardless of whether the plan is modified or not. To avoid unnecessary administrative work, recommend each Operating Plan only be provided once to the RC, unless notified by the RC.
Response: The SDT believes that this needs to be a 'push' mechanism rather than a 'pull' based on the Reliability Coordinator specifically requesting the Operating Plan in order to make this a 'routine' event that can be handed without becoming a burden. The SDT also believes that Reliability Coordinators will work with its Transmission Operators to come up with an arrangement so that duplicative Operating Plans do not need to be submitted. No change made.		
Electric Reliability Council of Texas, Inc.	No	The current definition of Operating Plan states "a document". Please refer to previous comments for IRO-008 related to this issue. For R3 and R5, please see previously provided comments for IRO-008 R4. For R4, the SDT should consider consistency of use of "Demand patterns" and "Load Forecast".
Response: See response to comments for IRO-008. See response to comments for IRO-008. The SDT believes that the terms have been used correctly. No change made.		
Texas Reliability Entity	No	1) R2: R2 should be explicit on the time frames that an SOL exceedance must be mitigated within TOP Operating Plans. Recommend adding language from or referencing the SOL Performance Summary, Figure 1 from the Project 2014-03 SOL Exceedance White Paper. The concept contained in the SOL whitepaper is clear but it must be transferred to the Operating Plan development process to ensure that SOLs are mitigated in the appropriate time frame to avoid any thermal or stability limit violations.

Organization	Yes or No	Question 8 Comment
		2) R4: Recommend adding a new BA requirement to have an Operational Planning Analysis (in line with R1 language for the TOP). Currently it appears there is a gap for the BA responsibilities. The BA should also have a requirement for an Operational Planning Analysis in order to develop their Operating Plan for the next day. The NERC Functional Model lists BA responsibilities "ahead of time" for integrating resource plans, including compiling load forecasts, approving operational plans and commitments from GOs, receiving generation maintenance schedules, etc. The Functional Model language mirrors the language contained in the definition of Operational Planning Analysis such as “The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; interchange; ....” 3) R's 3, 5, 6 and 7: Requirements R3, R5, R6 and R7: Recommend adding language similar to this: “Such notification (Plan) shall be delivered before the start of the day to which it applies.” Requirements R3, R5, R6 and R7 require the TOP (R3 and R6) and the BA (R5 and R7) to notify either impacted NERC registered entities or the RC but no time frame for when the notification must occur. The reliability benefit of these deliveries is much reduced if they are made too late for appropriate actions to be taken by the receiving entities.
Response: 1) The SDT believes that any needed timeframe will be part of an entity’s Operating Plan. In addition, the whitepaper will be appended to the standards. No change made. 2) The SDT does not believe that the Balancing Authority needs to perform an Operational Planning Analysis and that creation of an Operating Plan fulfills the needs for reliability. No change made. 3) The SDT believes that timeframes for delivering this information will be set up on case-by-case basis, that most areas already have such stipulations in place, and that they are all different based on a particular area’s needs. Any attempt to mandate a national limitation would be an exercise in futility. The SDT believes that the suggested language is not necessary. No change made.		
NV Energy	No	R1: Requires that the TOP shall have an OPA that will allow it to assess whether planned operations for the next day within TOP area will exceed any SOLs. This requirement fails to acknowledge that the “next day” for some OPAs will be several

Organization	Yes or No	Question 8 Comment
MidAmerican Energy		days in the future and not the immediately following day. Without that provision, it would mean that next day analyses must be conducted 365 days per year (if it only is valid for the "next" day). We suggest that the language be rephrased as follows: "...that will allow it to assess whether its planned operations for the Operations Planning horizon within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs)." R2: Same issue as with R1. Suggest changing the time frame of the Plan to be the Operations Planning horizon. R3: As stated, each TOP shall notify impacted NERC registered entities identified in the Operating Plan cited in R2 as to their role in the Plan. Suggest clarifying language inserted as follows "to the extent that any NERC registered entities are impacted" to allow for the likelihood that none are impacted. The requirement of notifying "four or more impacted NERC registered entities or more than 15% of the impacted NERC registered entities identified in the Operating Plan(s) as to their role in the plan(s)" is vague and potentially unenforceable. Suggest the SDT drop the four or more than 15% for "notify adjacent negatively impacted NERC registered entities". Is posting of the guide on the Region's web-site sufficient? If not, how do we define 15% of the impacted entities? R4: Here the BA shall have an Operating Plan. This has the same time frame issue as with R1 and R2, and we propose similar resolution.
Response: The SDT believes that the important aspect for reliability is to have a study that applies to the next day. If nothing changes from day to day then a new analysis would not be required. No change made. Requirements R1, R2, and R4 are already identified as *"Time Horizon: Operations Planning".* No change made. R3: The SDT believes that the term "impacted" excludes those entities not identified as such in the plan and that the suggested language does not add any clarity. No change made.		

Organization	Yes or No	Question 8 Comment
The SDT believes that the VSL language is clear. An entity knows how many other entities are impacted from its study and should be easily able to determine the 15% limit. No change made.		
SERC OC Review Group	Yes	In R3, M3, R5, & M5 a suggestion to change wording from “notify” to “coordinate”. Suggested wording in R3, R5: “shall coordinate with NERC registered entities identified in the Operating Plan(s)” instead of “shall notify impacted NERC registered entities”. Suggested wording in M3, M5: “shall have evidence that it coordinated impacted”.
Response: The SDT does not agree with replacing “notify” with “coordinate” because coordination is not measurable where notification is. Furthermore, the SDT believes that the notification initiates coordination. No change made.		
Peak Reliability	Yes	o R4.3. Does “demand pattern” simply mean a load forecast? If not, it should be clarified. If so, it should say “load forecast” as this term is more widely understood and used in the industry.
Response: The SDT believes that Load forecast can be interchanged with demand pattern. No change made.		
Tri-State Generation and Transmission Association, Inc.	Yes	As it is written R1 does not require the TOP to perform the analysis. The team should modify the requirement to "Each TOP shall perform an Operational Planning Analysis...."
Response: The SDT requires the Transmission Operator to have an Operational Planning Analysis allowing for flexibility in obtaining the Operational Planning Analysis. No change made.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	

Organization	Yes or No	Question 8 Comment
PPL NERC Registered Affiliates	Yes	
Rayburn Country Electric Cooperative	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Manitoba Hydro	Yes	
Exelon Companies	Yes	
Ingleside Cogeneration LP	Yes	
Xcel Energy	Yes	
ReliabilityFirst	Yes	
PNMR	Yes	
PJM Interconnection	Yes	
Austin Energy	Yes	
Ameren	Yes	
Consumers Energy	Yes	

Organization	Yes or No	Question 8 Comment
Oncor Electric Delivery LLC	Yes	
Hydro One	Yes	
Independent Electricity System Operator	Yes	
Hydro One	Yes	
INDN - Independence Power & Light	Yes	
Salt River Project	Yes	
Response: Thank you for your response.		

9. Do you agree with the changes made to proposed TOP-003-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

Summary Consideration: The SDT changed the Implementation Plan for Requirements R1 through R4 from 10 months to 9 months. Most of the other comments received were about clarifications of the proposed language. The SDT has provided the requested clarification and in addition has made the following change based on industry comments:

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

Organization	Yes or No	Question 9 Comment
Northeast Power Coordinating Council	No	To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and change "compliance investigations" to "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes. To be consistent with other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention. Under the section "Definitions of Terms used in the Standard" it is stated that there are no new or revised definitions proposed in this standard revision, however, the standard's use of "Operational Planning Analysis" is a revision to its definition.
Response: Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure. A reference to the updated definition of "Operational Planning Analysis" has been added to proposed TOP-003-3 as suggested. Based on this comment, the definition of "Real-time Assessment" has also been added. And conforming changes were made to proposed IRO-010-2.		

Organization	Yes or No	Question 9 Comment
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	R1 - Time Horizon should include Real-Time Operations and Same-Day Operations. R1.1 and R1.2: Does this mean a generic type of data required or a detailed list of data points? R2 - Time Horizon should include Real-Time Operations and Same-Day Operations. R2.1 and R2.2: Does this mean a generic type of data required or a detailed list of data points?
Response: The data specification is set up in advance in order for the Transmission Operator/Balancing Authority to receive the data it needs when it needs it. Therefore, the Time Horizon is not a Real-time or same-day issue but a 'planning' issue and is accurately recorded as Operations Planning. No change made. The requirements are designed to be a detailed list of data points.		
MRO NERC Standards Review Forum	No	R3 and R4 need to be reworded as it is believed that it is a request for data from the TOP (R3) and BA (R4) to other entities to be included into the prescribe analysis or assessment. Recommend R3 (and similar for R4) to read as: "Each Transmission Operator shall distribute its data specification to entities that have data (add) submittal requirements by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment".
Response: The SDT believes that the requirements are clear as written. No change made. The SDT does not believe that this suggested change adds clarity. No change made.		
Dominion	No	Dominion does not agree with R1.1 as written. We are opposed to the inclusion of the phrase "including sub-100 kV facilities". It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process.

Organization	Yes or No	Question 9 Comment
		Dominion does not see a distinct difference between sub-requirements 1.3 and 1.4. We believe that periodicity infers the deadline. Dominion does not see a distinct difference between sub-requirements 2.3 and 2.4. We believe that periodicity infers the deadline.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Transmission Operator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Transmission Operator would like to have to flesh out its models. The requirement as written will allow the Transmission Operator to obtain this data. No change made. Requirement R1, Part 1.3 (and Requirement R2, Part 2.3) refers to the periodicity of the data, i.e., how often the data must be supplied. Requirement R1, Part 1.4 (and Requirement R2, Part 2.4) refers to the deadline for the initial provision of the data point, i.e., when you need to respond to a new request for data. No change made.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, R1 and R2 should specify a “minimum” set of data requirements. This is especially apparent when protection system status is called out in 1.2 and 2.2, but the status of the Facilities being protected is not called out - which is more important to reliability? Due to the ambiguity of what is and is not included in R1 and R2, other SDTs for other standards were unwilling to accept that there is duplication (e.g., VAR-002, which was just revised, requires notification of voltage regulator status, and information about GSUs and tap settings, items which should also be included in the data specification). The only way to eliminate the duplication, redundancy and confusion in the standards will be to develop a minimum list of data in R1 and R2 so that it is clear that the data is included. FMPA believes that lack of specificity, while presumably simplifying the standards, actually makes them more complicated because we are unable to resolve overlap between standards. As such, we propose the SDT develop a “minimum” set of data, notification, information, etc.,

Organization	Yes or No	Question 9 Comment
		requirements as an attachment to the standard. TOPs and BAs can always specify more if so desired. In R5, what data is needed from the IA that is not provided by the BA? Likewise, all of the data needed from an LSE can also be provided by the DP (i.e., load forecasts). As a result, FMPA recommends eliminating IA and LSE from the requirement.
Response: The SDT believes that the requesting entity, in this case the Transmission Operator/Balancing Authority, is in the best position to know what it needs to preserve reliability. One size does not fit all here as each system is different. The requirement is written to respect that fact and to allow individual Transmission Operators/Balancing Authority's to craft the list as they see fit using its professional judgment. The Transmission Operator and Balancing Authority would always be able to suggest additional data points if the Transmission Operator/Balancing Authority did not request them initially. No change made. The SDT agrees and has removed the Interchange Authority from this requirement. There are active discussions about the future role of the Load-Serving Entity but for the moment it is included in the Functional Model v5. The SDT is required to follow that document in its work. If the group looking into the deletion of Load-Serving Entity decides to eliminate it, it will be the responsibility of that group to come up with a plan to bring the body of standards up to date. See summary consideration for revision.		
Duke Energy	No	R1: Duke Energy believes the Time Horizons should include Same-Day Operations and Real-Time Operations. This would capture the Time Horizon where Real-time monitoring and Real-time Assessments occur. R2: As written, Duke Energy believes the Time Horizon should be modified to Same-Day Operations and Real-Time Operations to be consistent with Real-time Monitoring. R3: No comments R4: No comments R5: No comments

Organization	Yes or No	Question 9 Comment
Response: The data specification is set up in advance in order for the Transmission Operator/Balancing Authority to receive the data it needs when it needs it. Therefore, the Time Horizon is not a Real-time or same-day issue but a 'planning' issue and is accurately recorded as Operations Planning. No change made.		
Bureau of Reclamation	No	Reclamation disagrees with TOP-003-3's proposal 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-003-03 should outline a specific continent-wide standard like the submission of planned generation outages over 50MW by noon on the day before the outage. 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 is likely to create operational challenges for entities operating in multiple Transmission Operator and Balancing Authority areas.
Response: Proposed TOP-003-3 allows the Transmission Operator and Balancing Authority to request the data that is needed to operate reliably. This can differ depending on the topology of the interconnected Transmission system, which could result in different data requirements and for different entities to come into play such as, Generator Owner, Generator Operator, and Transmission Owner. No change made. The Transmission Operator and Balancing Authority can continue to specify specific times for certain data in the data specification concept just as they did before. It can now be done on a case-by-case basis which is better for reliability. No change made. Proposed TOP-003-3 allows the Transmission Operator and Balancing Authority to request the data that is needed to operate reliably. This can differ depending on the topology of the interconnected Transmission system, which could result in different data requirements and for different entities to come into play such as, Generator Owner, Generator Operator, and Transmission Owner. No change made.		
SPP Standards Review Group	No	The Rationale Box under the Applicability Section explains why the Interchange Authority was absolved of responsibility for IRO-010-2. That same justification should

Organization	Yes or No	Question 9 Comment
		be used to remove the Interchange Authority from the Applicability Section of TOP-003-3. There is some confusion as to just what needs to be included in the data specification required in Requirement R1. In order to minimize confusion we recommend that the drafting team include clarification in the Application Guidelines which, for example, states that the specification does not have to be a point-by-point listing of all data points to be exchanged. Capitalize 'Part' in the Rationale Box for R1. Replace the 2nd line in the 2nd paragraph in the Rational Box with 'The language has been moved from approved PRC-001-1.' Capitalize 'Part' in the Rationale Box for R5.
Response: The SDT agrees and has removed Interchange Authority. See summary consideration for revision. Ultimately, a point-by-point listing will be necessary, although the process may begin with a higher-level specification, such as "all line statuses, MW/MVAR flows and bus voltages for all transmission assets controlled by this entity." It is doubtful that a Transmission Operator/Balancing Authority would necessarily know all of the points in detail for a new entity in its area, but likely that it would know the listing of points for existing, mature entities of that type. No change made. The SDT agrees and has made the suggested changes. The SDT agrees and has made the suggested change. The SDT agrees and has made the suggested change.		
ACES Standards Collaborators	No	(1) Requirement R5's language of "mutually agreeable" is challenging for compliance because it requires additional documentation to show that the data was submitted in a "mutually acceptable format." The requirement should be that entities must submit the applicable data by the required timeline. What should be a straight-forward process has been complicated for compliance purposes with this language.

Organization	Yes or No	Question 9 Comment
Response: The SDT does not believe that the suggested change adds clarity. No change made.		
Rayburn Country Electric Cooperative	No	Similar to my comments on IRO-001 and TOP-001 I think this could be combined with IRO-010 in a similar manner. GROUP 1Any of the following: Reliability Coordinator Balancing Authority Transmission Operator GROUP 2Any of the following: Transmission Operator Balancing Authority Generator Owner Generator Operator Interchange Authority Load-Serving Entity Transmission Owner Distribution Provider R1. GROUP 1 shall maintain a documented specification for the data necessary for it to perform its analysis, monitoring and assessments as required. The data specification shall include, but not be limited to: R2. GROUP 1 shall distribute its data specification to entities that have data required by (GROUP 1) to perform its analysis, monitoring and assessments. R3. A GROUP 2 member receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: 3.1. A mutually agreeable format 3.2. A mutually agreeable process for resolving data conflicts 3.3. A mutually agreeable security protocol Any specificity related to data required by each respective function should be identified within their data specification not within the reliability standard. For example, if the RC needs sub 100kV information, that can be identified with justification within the data specification.
Response: The SDT purposely kept proposed IRO-010-2 and proposed TOP-003-3 separate to keep the focus on the functional entities responsible: Reliability Coordinators for proposed IRO-010-2 and Transmission Operators and Balancing Authorities for proposed TOP-003-3. This was part of the scope for the originating projects (Project 2006-06 and Project 2007-03). No change made.		
Rutherford EMC	No	In the Table of Compliance Elements, the severity and risk for R5 is medium with only a Severe VSL. All other requirements in this standard are low and have graduated levels of severity. In IRO-10, the same failure has graduated levels of severity. This is inconsistent and should be rectified.
Response: Please see response to question 14.		

Organization	Yes or No	Question 9 Comment
Volkmann Consulting	No	TOP-003 should have additional requirements that requires the TOP or BA to determine and communicate any deficiency of data received back to the applicable entity providing the data. TOP-003 requires the sending of data to the TOP or BA, but does not require the determination of adequacy. For larger systems, it is impossible to prove every piece of data is being sent per the specification. In all cases the TOP or BA know if they have enough data, but performance of its real-time processes and tools. The TOP or BA should be required to communicate data deficiencies and not rely on the Audit process.
Response: The SDT believes that the requirements are written such that the onus for performance is on the Transmission Operator/Balancing Authority. Therefore, the Transmission Operator/Balancing Authority will have every reason to be continually checking the data for accuracy or any deficiencies and that this becomes a technicality that does not rise to the level of a mandatory standard. No change made.		
City of Garland	No	Requirement 1Concern There is no provision for small Transmission Operators who's Area (number / size of Facilities) is too small to financially justify installing the capability to run the analysis and assessment - all TOPs are not created equal.
Response: The SDT has allowed for the possibility of an entity performing analysis and assessment on its own or by contracting for it thus allowing for a minimal cost solution. For example, ERCOT could run these studies for Garland under the existing CFR. No change made.		
Ingleside Cogeneration LP	No	R1.1 allows the Transmission Operator to require downstream entities to provide certain sub-100 kV data and external network data needed to support operational reliability. Although ICLP agrees with the fundamental premise, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new Definition of the BES. This process was developed precisely for this reason - and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. Without this

Organization	Yes or No	Question 9 Comment
		limitation, we can see that the standard will be applied unevenly across Transmission Operators; which works against the fundamental intent of reliability standardization. Secondly, ICLP does not see the reasoning behind moving the responsibility for maintaining a mutually agreeable data format, data conflict resolution process, and security protocol to the data providers (R5). The TOP and BA should provide those specifications and processes under Requirements R1 and R2. If there is an issue with the term "mutually agreeable", the onus could be put on the data provider to demonstrate that an alternate format/process/protocol is needed in their specific instance.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Transmission Operator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Transmission Operator would like to have to flesh out its models. The requirement as written will allow the Transmission Operator to obtain this data. No change made. "Mutually agreeable" allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can't force a solution on the other entity when that entity may not be physically capable of performing**.** No change made		
American Transmission Company	No	ATC requests that the SDT consider the following recommended modifications: a. R1, R1.1, and R3 - See comments submitted under TOP-001-3 (Question #7) regarding proposed changes to the definition of "Real-time Assessment". If ATC's first proposal for changing the definition of "Real-Time Assessment" is not implemented, to eliminate redundant wording related to Real-time requirements, ATC suggests the term "Real-time monitoring" be removed from Requirements R1, R1.1, and R3 since the "Real-time Assessment" definition shown in draft Standard TOP-001-3 already requires assessing existing operating conditions. b. R1.1 - To provide consistency with proposed Requirement R10 of TOP-001-3, ATC suggests that Requirement R1.1 be modified by replacing "as deemed necessary by

Organization	Yes or No	Question 9 Comment
		the Transmission Operator” with “needed to maintain reliability within its Transmission Operator Area.” c. R1.2 - To provide consistency with proposed Requirement R10 of TOP-001-3, ATC suggests that Requirement R1.2 be modified by replacing “that impacts System reliability” with “needed to maintain reliability within its Transmission Operator Area.” d. R1.2 - To provide consistency with proposed Requirement R10 of TOP-001-3, ATC suggests that Requirement R1.2 be modified by replacing “that impacts System reliability” with “needed to maintain reliability within its Transmission Operator Area.” e. R2 - To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R2 be modified by replacing “perform its analysis functions and Real-time monitoring” with “perform its reliability functions.” f. R2.1 - To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R2.1 be modified by replacing “perform its analysis functions and Real-time monitoring” with “perform its reliability functions.” g. R2.2 - To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R2.2 be modified by replacing “that impacts System reliability” with “impacts generation or Load.” h. R4 - To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R4 be modified by replacing “analysis functions and Real-time monitoring” with “reliability functions.”

Response: a. The SDT does not believe that the suggested change adds clarity. No change made.

b. The SDT does not believe that the suggested change adds clarity. No change made.

c. The SDT does not believe that the suggested change adds clarity. No change made.

d. The SDT does not believe that the suggested change adds clarity. No change made.

Organization	Yes or No	Question 9 Comment
e. The SDT does not believe that the suggested change adds clarity. No change made. **f.** The SDT does not believe that the suggested change adds clarity. No change made. g. The SDT does not believe that the suggested change adds clarity. No change made. h. The SDT does not believe that the suggested change adds clarity. No change made.		
American Electric Power	No	Please provide reasoning for the removal all references to the NERC Confidentiality Agreement from TOP-005-2. R1: How detailed would the data specifications need to be, especially in regards to data between other entities, in order to satisfy the requirement? R3: For data taken from NERC SDX, how would a data specification be sent? There is an established process in SDX for sharing data, and this proposed standard does not align with it. R5: This does not align with current practices of going through the RC for transferring operational data between NERC entities. R5.3: The phrase “Mutually agreeable security protocol” is vague and is subjective due to its potential interpretation by various entities and regions.
Response: As pointed out in the mapping document, the SDT has added security protocols to proposed IRO-010-2, Requirement R3, Part 3.3 and to proposed TOP-003-3, Requirement R5, Part 5.3 to address overall security concerns. As detailed as necessary for the issuing entity to assure reliability. It could initially be a high-level request, with discussion and interaction to produce the list of data points necessary to assure reliability. The mechanism by which the data is shared is part of “how” this is accomplished. The SDT believes that SDX and other technologies do fit within this standard. The entity issuing the data specification may need to review whether the periodicity of SDX data is sufficient to meet its reliability needs. Transferring data through a Transmission Operator/Balancing Authority is part of “how” this could be accomplished. This would adhere to the requirements as long as periodicities, etc. are met.		

Organization	Yes or No	Question 9 Comment
The standard anticipates data to be supplied via a secure mechanism/medium. The exact mechanism/medium is part of the "how" it is to be accomplished. No change made.		
Ameren	No	R1: We ask the drafting team for clarification. What data would be necessary from outside entities for us to perform "Operational Planning Analyses"? Would this need to be forwarded to those entities? R5: We ask the drafting team for clarification; how will we be able to prove compliance with this unless someone provided us with any data specifications satisfying said data specification transfer if it means an automatic type of data dump. Does the drafting team mean providing some data manually on a real time basis (line just tripped, etc.), that would fall in the TOS realm or with ICCP data transfer?
Response: The Transmission Operator runs its own Operational Planning Analysis and, therefore, it is in the best position to know what data is needed, and if the data is controlled/supplied by an external entity, then it must supply the data specification asking for that data to be supplied. Measure M5 states "Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities. " The SDT believes that this gives ample opportunities for proving compliance. A simple attestation from the requesting entity that the data has been supplied in accordance with the specification is one possible way to prove compliance.		
Liberty Electric Power, LLC	No	See comment provided for the similar IRO standard.
Response: See comment response for the IRO standard.		
ITC	No	Regarding R1.1, the inclusion of sub-100 kV facilities is not relevant as the requirement should focus monitoring on BES elements only. If a sub-100 kV facility is included in BES per the definition it should be monitored.

Organization	Yes or No	Question 9 Comment
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Transmission Operator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Transmission Operator would like to have to flesh out its models. The requirement as written will allow the Transmission Operator to obtain this data. No change made.		
Electric Reliability Council of Texas, Inc.	No	Additional thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.
Response: Protection Systems were added due to concerns raised in NOPR paragraph 78. The intent of such changes is to ensure that Transmission Operator/Balancing Authority can maintain an appropriate level of situational awareness. While the SDT believes that this will result in an additional burden on entities, it believes that this incremental increase is relatively minor and necessary for reliability. No change made. The SDT believes that the implementation time frame of 12 months is adequate. Nearly all, if not all, of the data that a Transmission Operator/Balancing Authority might need for reliability is already in place and telemetered to the Transmission Operator/Balancing Authority. The 12 month period will allow for any additional work that might be needed to be accomplished. Adoption of this standard does not create a massive new data transfer effort. No change made.		
Texas Reliability Entity	No	1) General: Texas Reliability Entity disagrees with use of the phrase "specification for the data necessary" in the Requirements of this standard. This phrase appears to meet the definition of the so-called "fill-in-the-blank" standards that FERC and the industry are seeking to avoid. NERC's Work Plan for Addressing Fill-In-The-Blank Reliability Standards (October 4, 2006) defines fill-in-the-blank standards as

Organization	Yes or No	Question 9 Comment
		"...those that depend on regional criteria or procedures not currently contained within certain Reliability Standards, but which are needed to provide additional requirements for implementing the standards within the regions." This standard as written does exactly that: depends on regional criteria or procedures not currently in standards that are needed for an entity to achieve compliance. This standard does not meet the following criteria identified in NERC's Quality Objectives: clear and defined performance requirements, measurable, complete and self-contained standards and consideration of comments. The SDT addressed multiple commenters who expressed concern with the phrase "specification for the data necessary" during the comment period for TOP-003-2 under Project 2007-03 with the following: "The data specification concept has already been approved by FERC for Reliability Coordinators in the IRO standards. No change made." The response indicates that the SDT may not have fully considered the concerns that were raised by the lack of specificity within the standard as currently written. While Texas RE understands the SDT is trying to allow flexibility to determine what data they need to perform their duties, there must be a minimum set of data that each TOP and BA needs to adequately fulfill their operational and planning responsibilities, therefore contributing to the reliability of the BPS. Recommend expanding R 1.1 and 2.1 to include a list of "at a minimum, data specification must include..." applicable to what the TOP and BA respectively need to perform their functions. Alternatively, recommend adding technical guidance similar to recently FERC approved MOD-032-1, Attachment 1 and application guidelines to include the types of data that must be provided by each TOP, BA, GO, GOP, IA, LSE, TO and DP as required in R5. 2) R1.1: Recommend enclosing in commas and moving the phrase “needed by the Transmission Operator” to before “sub-100”. The phrase “needed by the Transmission Operator” is positioned wrong to be clearly understood as applying to the “including sub-100 kV data and external network data” portion of the Requirement. It appears in the paragraph as a modifier that applies to the entire list of data and information.

Organization	Yes or No	Question 9 Comment
		3) R 1.2: The meaning of the word "Provisions" is unclear in the context of this sub-requirement. Is it meant that the RC shall provide a tool (such as a web portal) for entities to notify the RC of Protection System and Special Protection System status? Or is it meant that the RC shall identify how notification should be made? If the latter, the word "provisions" should be replaced by "specifications". (Same comment was made for IRO-010, R 1.2) 4) R2: Recommend replacing “analysis functions” with “Operational Planning Analysis”. It appears there is a gap for the BA responsibilities. Under the Functional Model, the BA is responsible ahead of time for integrating resource plans, including compiling load forecasts, approving operational plans and commitments from GOs, receiving generation maintenance schedules, etc. The Functional Model language mirrors the language contained in the definition of Operational Planning Analysis such as “The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; interchange; ....” 5) R3 and R4: Recommend adding the word "current" in front of "data specification" to account for the possibility that the data specification can change. For example if the specification is changed from average MW capability for the year to the summer rating then the revised (or "current") data specification must be distributed to entities that have data required by the TOP (R3) or the BA (R4).

Response: 1) The SDT disagrees. Each Reliability Coordinator/Transmission Operator/Balancing Authority faces unique challenges that should allow them to be able to tailor the data specification accordingly. No change made.

2) The SDT does not believe that the suggested change adds clarity. No change made.

3) “Provisions” allows for multiple solutions – the standard only states what must be done, not how it must be accomplished. No change made.

4) The SDT does not agree that the Balancing Authority should be required to have an Operational Planning Analysis. The Balancing Authority does perform analyses that are both Real-time, day-of, next-day and forward looking, but these are not the same as the Operational Planning Analysis. No change made.

Organization	Yes or No	Question 9 Comment
5) The SDT does not believe that the suggested change adds clarity. No change made.		
Georgia Transmission Corporation	No	(1) GTC disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity if determined to be BES. (2) Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly impact reliability, are redundant, and handle data requests and submittals.
Response: (1) Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Transmission Operator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Transmission Operator would like to have to flesh out its models. The requirement as written will allow the Transmission Operator to obtain this data. No change made. (2) This requirement codifies the requirement to make available the data necessary to assure reliability and to address specific issues raised in the NOPR. The SDT does not agree that these are administrative requirements. No change made.		
Salt River Project	No	R2 requires entities to provide a specification for all data necessary for analysis and real time monitoring which will result in a massive specification that could include all ICCP points used for modeling, dynamic signals & pseudo ties, BA tie lines, elements of NSI & NAI, SPS & RAS status & alarm points and a multitude of other data that may be required. The data required here is very dynamic and will change in a very short period of time. Any specification created initially to meet this requirement will very soon become outdated. R2.3 requires a BA to review the periodicity for providing data. Does a BA need to review each data point and determine appropriate periodicity? Does this periodicity apply for a BA's internal data, external data, or both? With the scan rates already required in BAL-005-1b R8, why is this requirement necessary?

Organization	Yes or No	Question 9 Comment
		R2.4 references a respondent for data but does not specify who the respondent would be. R4 requires BAs to distribute data specifications to other entities. For a BA with many adjacent entities, this will become a significant increase in workload and resources to distribute the specifications, and then document and maintain compliance evidence that this specification was received and that data was provided by each entity. This is burdensome and would only minimally increase reliability. A BA with several adjacent entities will need to negotiate a format, conflict resolution and security protocols with each individual entity per R5.1, R5.2, and R5.3. This will result in a significant number of individual agreements with each entity. Creating these agreements, maintaining these agreements and then maintain compliance evidence for each agreement is burdensome with only a minimal enhancement in reliability. SRP suggests the creation of a regional committee to address those conflicts in exchanging necessary operational data that might occur between entities. If an entity is not able to obtain necessary operating data from an entity, they could provide a report to this committee and the committee could resolve the conflict. This would allow entities to obtain the data needed and avoid the significant burden associated with this standard.

Response: The SDT believes that the process described is flexible enough to allow for updates as frequently as necessary to support reliability. No change made.

Periodicity is determined by the Balancing Authority to support its reliability needs. The periodicity may be different for different points and the Balancing Authority is in the best position to determine the exact periodicity needed. The indicated requirement only applies to ACE calculation data. The Balancing Authority deals with more than just that data so the periodicity requirement is needed. No change made.

The respondent, from the context of the sub-requirement, is the entity that has received a data specification from the Balancing Authority. No change made.

Balancing Authorities with multiple interconnections must coordinate with all of their neighbors in order to assure reliability. This burden is not changed significantly with this requirement. No change made.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td>NV Energy

MidAmerican Energy</td><td>No</td><td>R1 and R2 represent a significant documentation effort on the part of TOPs and BAs. It is supportable as written, but it will require a significant effort within typical grid operations staff to maintain the data specification and process the interactions with the entities who will be supplying the data.

R3 and R4 should be clarified as: “Each Transmission Operator shall distribute its data specification to entities that have data (add) submittal requirements by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessment”. This will limit the specification to only that data which is needed for these analyses, monitoring and assessments.

Regulators have stated they will not accept attestations in the future.</td></tr>
<tr><td colspan="3">Response: Thank you for your support.

The SDT does not agree. The Transmission Operator and Balancing Authority have the right to ask for any data that is needed to support reliability. No change made.

The SDT is not aware of any movement to not accept attestations in the future. No change made.</td></tr>
<tr><td>SERC OC Review Group

Associated Electric Cooperative, Inc. - JRO00088</td><td>Yes</td><td>1) In R3 & R4, insert term ‘NERC registered’ before ‘entities’. Due to temperature readings being obtained from the National Weather Service (NWS), some may consider the NWS to be an entity requiring the data specifications. Current: “Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.” Suggested: “Each Transmission Operator shall distribute its data specification to NERC registered entities that have data required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.”

2) Suggestion to add “R5.4 A mutually agreeable reliability need”</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
		3) In R5, for the entity receiving a data request, it would be preferred that some language is added to allow them to coordinate the request to ensure a sufficient reliability need. See response to Question 4 above.
Response: The SDT does not believe that the suggested change adds clarity. No change made. The standard gives the Transmission Operator/Balancing Authority the power to request anything needed for reliability. There is no requirement to demonstrate the need for this data, as, by definition, the Transmission Operator/Balancing Authority is the function charged with preserving the reliability of the interconnected power system for its area. No change made.		
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	The word 'Coordinator' should be added after the word 'Reliability' in the last sentence of the Rationale paragraph for R1. Southern suggest adding the words, 'NERC registered' after the word 'to' in requirement's 3 & 4 and Measures 3 & 4, and adding the phrase, 'a reliability-related need for', after the words, 'that have' in requirement's 3 & 4 and Measures 3 & 4. Suggested Requirement language: R3. Each Transmission Operator shall distribute its data specification to NERC registered entities that have a reliability-related need for data required by the Transmission Operator's Operational Planning Analysis, Real-time monitoring, and Real-time assessment.R4. Each Balancing Authority shall distribute its data specification to NERC registered entities that have a reliability-related need for data required by the Balancing Authority's analysis functions and Real-time monitoring. Suggested Measure language: M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to NERC registered entities that have a reliability-related need for data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to NERC registered entities that have a reliability-related need for data required by the Balancing Authority's analysis functions and

Organization	Yes or No	Question 9 Comment
		Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.
Response: The Rationale Box actually contains the word "Coordinator" but it was obscured in the posted version due to a formatting issue. This has been corrected. The SDT does not believe that the suggested changes add clarity. No change made.		
ISO/RTO Standards Review Committee (SRC) Independent Electricity System Operator	Yes	We agree with all the elements in the standard except the VSL for R5. Please see our comments under Q14, below.
Response: See response to question 15.		
Peak Reliability	Yes	R5: The IA should be removed. In the INT Re-write project, all operational requirements on the IA were removed and put on the sink BA. Consistent with that, the IA should be removed from this Requirement. R5: The "mutually agreeable" language is potentially problematic, as it is unclear how the entity will receive the data if they cannot reach agreement on the format. Using "a clearly defined format" would be better.
Response: The SDT agrees and has removed Interchange Authority from the standard. See summary consideration for revision. "Mutually agreeable" allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can't force a solution on the other entity when that entity may not be physically capable of performing**.** No changes made		
ReliabilityFirst	Yes	ReliabilityFirst submits the following comments for consideration: 1. Requirement R1, Part 1.1 - The phrase "as deemed necessary" is ambiguous and leaves the

Organization	Yes or No	Question 9 Comment
		requirement open to interpretation and therefore, difficult to enforce. To provide specificity, the requirement should state "... including sub-100 kV but greater than 50 kV data". This language is consistent with the NERC BES definition, and has a technical justification developed by that SDT.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Transmission Operator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process or that are over 50 KV, it is also true that there may be sub-100 kV points that are not needed as part of the BES or over 50 kV but which the Transmission Operator would like to have to flesh out its models. The requirement as written will allow the Transmission Operator to obtain this data. No change made.		
Idaho Power	Yes	I do not have a problem with TOP-003-3 but feel it should be combined with IRO-010-2 as the requirements are basically the same only the applicability is different.
Response: The SDT purposely kept proposed IRO-010-2 and proposed TOP-003-3 separate to keep the focus on the functional entities responsible: Reliability Coordinators for proposed IRO-010-2 and Transmission Operators and Balancing Authorities for proposed TOP-003-3. This was part of the scope for the originating projects (Project 2006-06 and Project 2007-03). No change made.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	
PPL NERC Registered Affiliates	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 9 Comment
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Manitoba Hydro	Yes	
Exelon Companies	Yes	
Xcel Energy	Yes	
PNMR	Yes	
David Kiguel	Yes	
PJM Interconnection	Yes	
Austin Energy	Yes	
Consumers Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Hydro One	Yes	

Organization	Yes or No	Question 9 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Response: Thank you for your response.		

10. The mapping document posted on the project page explains how the drafting team believes Requirements from 5 IRO standards that are proposed for retirement are addressed without creating any reliability gaps. Do you agree with the retirement of standards IRO-003-2, IRO-004-2, IRO-005-3.1a, IRO-015-1, and IRO-016-1? If not, why not? Please be specific.

Summary Consideration: The overwhelming majority of the commenters agreed with the retirements as proposed and no changes were made to the list of proposed retired standards.

Organization	Yes or No	Question 10 Comment
Duke Energy	No	Until the proposed language is significantly modified and we are comfortable with those modifications, it is difficult for Duke Energy to determine if any reliability gaps exist with the recommended retirement of the 5 IRO standards that are proposed for retirement.
Response: Thank you for your response.		
Electric Reliability Council of Texas, Inc.	No	ERCOT agrees with retirement of IRO-003-2, IRO-005, IRO-015, and IRO-016. ERCOT does not agree with the current method to retire IRO-004-2 because the current definition for Operating Instruction is for Real Time only.
Response: The SDT believes that the "Real-time" term in the definition of an Operating Instruction describes the operating personnel issuing the command, but the SDT does not believe that the "Real-time" term applies to the timeframe of the intended "change or preserve" action, nor does it apply to the timeframe of the identified reason for the command. Therefore, personnel responsible for Real-time operations of a Reliability Coordinator could issue a valid Operating Instruction to a Transmission Operator, Balancing Authority, or Transmission Service Provider to take or plan to take appropriate actions to address projected system conditions that were identified in an Operational Planning Analysis of the next day. No change made.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 10 Comment
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI supports comments posted by the SERC OC Work Group
FRCC Operating Committee (Member Services)	Yes	
MRO NERC Standards Review Forum	Yes	
Colorado Springs Utilities	Yes	
SERC OC Review Group	Yes	
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	
Dominion	Yes	
Florida Municipal Power Agency	Yes	

Organization	Yes or No	Question 10 Comment
PPL NERC Registered Affiliates	Yes	
FirstEnergy	Yes	
SPP Standards Review Group	Yes	
ACES Standards Collaborators	Yes	We agree with the retirement of the above mentioned standards.
Peak Reliability	Yes	
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
Rayburn Country Electric Cooperative	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Manitoba Hydro	Yes	
Exelon Ccompanies	Yes	

Organization	Yes or No	Question 10 Comment
Seminole Electric Cooperative, Inc.	Yes	
Ingleside Cogeneration LP	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	ATC agrees with the retirement of the Requirements of the noted IRO Standards applicable to its registered functions as identified on the Mapping Document.
PNMR	Yes	
David Kiguel	Yes	
PJM Interconnection	Yes	
Austin Energy	Yes	
Consumers Energy	Yes	
Liberty Electric Power, LLC	Yes	
Oncor Electric Delivery LLC	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 10 Comment
INDN - Independence Power & Light	Yes	
Georgia Transmission Corporation	Yes	We agree with the retirement of the above mentioned standards.
Salt River Project	Yes	
NV Energy	Yes	
MidAmerican Energy	Yes	
Response: Thank you for your response.		

11. **The mapping document posted on the project page explains how the drafting team believes Requirements from 5 TOP standards and 1 PER standard that are proposed for retirement are addressed without creating any reliability gaps. Do you agree with the retirement of standards TOP-004-2, TOP-005-2a, TOP-006-3, TOP-007-0, TOP-008-1, and PER-001-0? If not, why not? Please be specific.**

Summary Consideration: No changes were made to any proposed requirements due to industry comments as most comments were concerned about the mapping of the original requirements to the new proposed standards. Several references have been corrected in the mapping document as a result.

Organization	Yes or No	Question 11 Comment
Northeast Power Coordinating Council	No	We do not agree with retiring PER-001 R1. This requirement requires operating personnel to have the authority to shed load without consulting non-operating management personnel. There have been instances where load shedding was delayed by non-operating managers or attempts to seek permission to shed load. The System Operator is responsible for maintaining a reliable system in Real-time and they should have full authority to shed load. The SDT reference to the FERC Order does not apply to PER-001. We do not agree with retiring TOP-002 R19. R19 requires the TOP to have an accurate model. The Planning Coordinator model may not be suitable for operations. There are scripts that can convert the Planning model into an Operations model, but these are not uniformly available. The new requirements for conducting an Operating Planning assessment and Real Time Assessment imply that operations has an accurate model. Referring to MOD-033 does not properly support retirement. MOD-033 places a requirement on the PC to have a model but does not require the PC to provide it to the TOP. The question of who is responsible for accuracy of the Real-time model is not answered in MOD-033. The fact that the TOP has to provide behavior data to the PC does not mean it has an accurate model. Agree with retiring TOP-004 R5 requiring remaining connected to the Grid, but suggest the justification is in the proposed TOP-0013 R14 and R15.

Organization	Yes or No	Question 11 Comment
		Agree with retiring TOP-006 R4 but do not agree with the justification pointing to TOP-003. TOP-006 R4 requires a load forecast to be completed for Operational Planning. The justification states this, but it should point to Operational Planning TOP-002-4 R1 and R2. Agree with retiring TOP-006 R6 but do not agree with the justification pointing to BAL-005 frequency metering. TOP's monitor line flows, voltages, SOL and IROL. These items have nothing to do with BAL standards. This requirement sets the stage for situational awareness and monitoring tools. The better reference is TOP-001 R10 which requires the TOP to monitor.

Response: PER-001 R1**:** Whether or not an entity provides its operating personnel with the responsibility and authority to implement Real-time actions, the entity, not the personnel, is subject to standards and requirements for specific actions to maintain reliable system operating conditions. For example, refer to approved EOP-002-3.1 Requirement R1, approved EOP-003-2 Requirements R6 and R8, and the proposed TOP-001-3 Requirements R1 and R2. No change made.

TOP-002 R19: The SDT would point out that there is not a similar requirement applicable to the Reliability Coordinators to maintain accurate computer models, yet none have been proposed, nor have any reliability issues been attributed to the lack of such a requirement. After referring to the Application Guidelines developed along with approved MOD-033-1, the SDT also acknowledges the impracticality of attempting to define what an accurate computer model is or how to measure it. However, the SDT believes that through Good Utility Practices and the application of the requirements in the proposed TOP and IRO Standards which require Transmission Operators and Reliability Coordinators to perform overlapping Operational Planning Assessments and Real-time Assessments and sharing results that this will help to identify modeling issues. No change made.

TOP-004 R5**:** The SDT agrees and the Mapping Document will be revised to refer to proposed TOP-001-3 Requirements R14 and R15.

TOP-006 R4: Approved TOP-006-3 Requirement R4 actually only requires information to be available, much like proposed TOP-003-3 Requirements R1 and R2 require a specification for necessary data. Proposed TOP-002-4 Requirements R1 and R2 require the application of that information through an Operational Planning Analysis. No change made.

TOP-006 R6: Rather than continuing the use of vague, undefined, and immeasurable terms such as sufficient, suitable, accurate, and timely, as used in approved TOP-006-3 Requirement R6, the SDT believes that this subject is adequately addressed by proposed TOP-001-3 Requirements R10 and R11 which require Transmission Operators and Balancing Authorities to monitor their respective areas. Standards referenced in the Mapping Document will be revised to include proposed TOP-001-3. No change made.

Organization	Yes or No	Question 11 Comment
Duke Energy	No	Until the proposed language is significantly modified and we are comfortable with those modifications, it is difficult for Duke Energy to determine if any reliability gaps exist with the recommended retirement of the 5 TOP standards and 1 PER standard that are proposed for retirement.
Response: Thank you for your response.		
SPP Standards Review Group	No	With the retirement of Requirement R1 of PER-001-0.2, the requirement for operating personnel to have the responsibility and authority to operate to maintain the reliability of the BES is eliminated. Such action reverts to conditions pre-1965 and the Northeast blackout. Do we as an industry feel this is where we need to be at this time? Where does that responsibility and authority lie following retirement? Is this captured in other requirements in the standards? If so, which ones?
Response: Whether or not an entity provides its operating personnel with the responsibility and authority to implement Real-time actions, the entity, not the personnel, is subject to standards and requirements for specific actions to maintain reliable system operating conditions. For example, refer to approved EOP-002-3.1 Requirement R1, approved EOP-003-2 Requirements R6 and R8, and the proposed TOP-001-3 Requirements R1 and R2. No change made.		
ISO/RTO Standards Review Committee (SRC) Independent Electricity System Operator	No	We agree with all the proposed retirements except TOP-004-2, Requirement R4.R4 stipulates that "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." While the intent is covered by the revised definition for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, neither definitions specifically ask for the verification of existing SOLs/IROLs or the determination of valid SOLs/IROLs as system condition changes go beyond the conditions covered by previous SOL/IROL calculations. Requirement R4 thus should be retained (and mapped into TOP-001-3) unless the two definitions are revised to require the

Organization	Yes or No	Question 11 Comment
		verification/determination of SOLs/IROLs through Operational Planning Analysis and Real-time Assessment. Not retaining R4, or without changing the definitions for the two terms, a responsible entity may project or enter an unknown state (for which valid SOLs/IROLs may not exist). An Operational Planning Analysis and Real-time Assessment at this time may indicate expected system performance, which may be unacceptable from an equipment loading, voltage level or stability viewpoint, but still there exist no SOLs/IROLs as a target to guide the responsible entity to adjust the BES to arrive at an acceptable state.
Response: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made.		
Electric Reliability Council of Texas, Inc.	No	TOP-006 R6 is not captured accurately. If the BAL-005 standard is intended to address metering outside of generation resources and the equipment that ties it to the BES, then the TO/TOP should be added to the BAL-005 R17 requirement. ERCOT suggests creating a requirement that addresses accuracy, range, and sampling rate holistically and apply it to Transmission Owners and Generation Owners as they typically purchase and maintain such devices. ERCOT does not agree that TOP-004 R6.2 is addressed sufficiently in TOP-001-3 R8. ERCOT believes that all switching that could impact another Transmission Operator should be coordinated, and not a subset which R8 limits it to. Failure to coordinate by the Transmission Operators that have local or direct control could result in inadvertent loss of load. ERCOT does not agree with the justification utilized for TOP-002 R19. Planning models may differ from Operations models due to software variances, new / retired facilities timelines, seasonal variations, etc. Therefore MOD-033-1 does not address R19.

Organization	Yes or No	Question 11 Comment
Response: TOP-006 R6**:** Revisions to the BAL Standards are outside of the scope of this SDT. However, rather than continuing the use of vague, undefined, and immeasurable terms such as sufficient, suitable, accurate, and timely, as used in approved TOP-006-3 Requirement R6, the SDT believes that this subject is adequately addressed by proposed TOP-001-3 Requirements R10 and R11 which require Transmission Operators and Balancing Authorities to monitor their respective areas. Standards referenced in the Mapping Document will be revised to include proposed TOP-001-3. No other change made. TOP-004 R6.2: Although proposed TOP-001-3 Requirement R8 is cited individually in the Mapping Document as the replacement for proposed TOP-004-2 Requirement R6.2, the proposed standards do not limit the coordination to a subset, but rather increases the level of coordination through requirements for formal outage coordination between Reliability Coordinators and Transmission Operators. As a whole, if the standards are followed, outage coordination as well as Operational Planning Assessments should identify all potential adverse impacts. Proposed TOP-001-3 Requirement R8 is from the Transmission Operators perspective and proposed IRO-008-2 is from the Reliability Coordinator's perspective. Combined, these actions are designed to thoroughly review planned operations and therefore accomplish the coordination that was vaguely referred to as coordination of switching transmission elements. No change made. TOP-002 R19: The SDT would point out that there is not a similar requirement applicable to the Reliability Coordinators to maintain accurate computer models, yet none have been proposed, nor have any reliability issues been attributed to the lack of such a requirement. After referring to the Application Guidelines developed along with approved MOD-033-1, the SDT also acknowledges the impracticality of attempting to define what an accurate computer model is or how to measure it. However, the SDT believes that through Good Utility Practices and the application of the requirements in the proposed TOP and IRO Standards which require Transmission Operators and Reliability Coordinators to perform overlapping Operational Planning Assessments and Real-time Assessments and sharing results that this will help to identify modeling issues. No change made.		
Peak Reliability	Yes	TOP-004 R5 - The requirement being retired deals with separation, but the mapping document references load shed language from the Functional Model. Separation may occur without load shed, so it is not clear that the coordination of separation is completely covered. TOP-008 R1 - The requirement being retired has the language "or contributing to an IROL or SOL violation", and the requirements in the mapping document may be missing coverage for SOLs outside of the TOPs area.

Organization	Yes or No	Question 11 Comment
Response: TOP-004 R5: Extreme operator actions such as separating from the interconnection would be coordinated under the proposed TOP-001-3 Requirements R14 and R15. The Mapping Document will be revised to refer to proposed TOP-001-3 Requirements R14 and R15. TOP-008 R1: Proposed TOP-001-3 Requirements R12 and R14 are not limited to SOLs or IROLs inside the Transmission Operators Area. If the identified exceedance is in another area and not identified by the contributing Transmission Operator, then Operating Instructions could be issued by the applicable Reliability Coordinator to instruct the Transmission Operator to take immediate steps to relieve the condition, which may include shedding firm Load. No change made.		
Idaho Power	Yes	I do not have a problem with TOP-003-3 but feel it should be combined with IRO-010-2 as the requirements are basically the same only the applicability is different. Combining the two standards would be best. The best solution would be to have a clearing house for all the data. The BA would submit the data to the RC on behalf of the TOP & GOP and it would be available for all other BA's.
Response: The SDT purposely kept proposed IRO-010-2 and proposed TOP-003-3 separate to keep the focus on the functional entities responsible: Reliability Coordinators for proposed IRO-010-2 and Transmission Operators and Balancing Authorities for proposed TOP-003-3. This was part of the scope for the originating projects (Project 2006-06 and Project 2007-03). No change made.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI supports comments posted by the SERC OC Work Group
FRCC Operating Committee (Member Services)	Yes	

Organization	Yes or No	Question 11 Comment
MRO NERC Standards Review Forum	Yes	
Colorado Springs Utilities	Yes	
SERC OC Review Group	Yes	
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	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
PPL NERC Registered Affiliates	Yes	
FirstEnergy	Yes	
ACES Standards Collaborators	Yes	We agree with the retirement of the above mentioned standards.

Organization	Yes or No	Question 11 Comment
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
Rayburn Country Electric Cooperative	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Manitoba Hydro	Yes	
Exelon Companies	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Ingleside Cogeneration LP	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	ATC agrees with the retirement of the Requirements of the noted TOP Standards applicable to its registered functions as identified on the Mapping Document.
PNMR	Yes	

Organization	Yes or No	Question 11 Comment
David Kiguel	Yes	
PJM Interconnection	Yes	
Austin Energy	Yes	
Consumers Energy	Yes	
Liberty Electric Power, LLC	Yes	
Oncor Electric Delivery LLC	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
INDN - Independence Power & Light	Yes	
Georgia Transmission Corporation	Yes	We agree with the retirement of the above mentioned standards.
Salt River Project	Yes	
NV Energy	Yes	
MidAmerican Energy	Yes	
Response: Thank you for your response.		

12. The SDT is seeking input on whether 30 minutes is the correct periodicity for the performance of Real-time Assessments for Reliability Coordinators and Transmission Operators. Please explain what you feel the correct periodicity and supply technical rationale for your suggestion.

Summary Consideration: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including approved EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards noted, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability

The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity's Loss of Control Center Functionality Operating Plan.

Finally, the standard does not mandate a specific toolset required to perform a Reliability Assessment nor does it specify the type of evaluation that has to be performed when tools are unavailable. The SDT expects that some type of evaluation is performed at least every 30 minutes regardless of capability availability. However, the SDT feels that the definition of Real-time Assessment along with the changes made to the requirement language, provide flexibility and allows for other types of evaluation methods for periods where normal tools are unavailable or during EMS failures. The SDT feels that is important for entities to recognize the need for situational awareness even during periods where primary systems are unavailable.

The SDT made the following changes due to industry comments:

Proposed TOP-001-3, Requirement R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed IRO-008-2, Requirement R5: Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Organization	Yes or No	Question 12 Comment
Duke Energy	No	While Duke Energy agrees, in general, that a Reliability Assessment shall be performed at least once every 30 minutes, we have concerns with this zero tolerance requirement. We believe a provision that allows for a defense in depth strategy is needed to allow the RC and/or TOP to develop a plan, process, or procedure for those instance where various tool(s) used to conduct the Reliability Assessment are unavailable for longer than 30 minutes. This would align with NERC's transition to the RAI Initiative. In addition, EOP-008-1 R1.5 allows a transition period of less than or equal to 2 hours for a RC and/or TOP to transition to its backup control center. If a RC and/or TOP is in its transition phase and it takes longer than 30 minutes to become fully implemented, would the RC and/or TOP violate R13 of this requirement? It could take longer than 30 minutes for an entity to arrive at the backup control center for various reasons. This is one of the reasons why a defense in depth strategy is needed in this requirement.
PJM Interconnection	Yes	PJM supports the 30 minute periodicity. Specific to IRO-008-2, R5, PJM is concerned with the compliance overlap and potential non-compliance with EOP-008, R5 which provides for a two hour timeframe to have the back-up facility fully functional. PJM recommends the addition of language in IRO-008-2, R5 to provide relief to the RC for the period when evacuation to the back-up facility is necessary and the timeframe it takes for the back-up control center to be fully functioning. Additionally, the VRF and VSLs for R5 will require revision to address the two hour timeframe allowed for in EOP-008.
Electric Reliability Council of Texas, Inc.	Yes	ERCOT believes that 30 minutes is the correct periodicity for normal operations. There should be flexibility in the requirement to account for instances when analysis tools may be unavailable temporarily recognizing the balancing of time to both trying to make the tools available again and or taking alternative means of conducting a Real Time Assessment. Recommendation could be to amend the requirement

Organization	Yes or No	Question 12 Comment
		allowing for notification to affected entities and taking alternative actions to conduct a Real Time Assessment within 60 minutes of the last RTA.
NV Energy	No	As noted in comments to prior questions, the 30 minute periodicity is inappropriate. As noted earlier, we believe that the intent here should be that the Operator has situational awareness, not that one meets a quota of RTA executions. The 30 minute period is also in conflict with certain EOP requirements which allow up to 2 hours to reestablish control center functionality. Further, a 30 minute requirement would almost necessitate backup means of conducting RTAs, as there is little tolerance for a failure of the tools.

Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability.

The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity's Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or

Organization	Yes or No	Question 12 Comment
even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.		
Bonneville Power Administration	No	BPA proposes 60 minutes as the correct periodicity. This allows time to set up, run and analyze the results of studies, especially if stability analyses must be performed.
SPP Standards Review Group INDN - Independence Power & Light		We tend to lean toward a not so prescriptive quantitative time limit but toward a more practical justification for why the assessment is needed. It can be dependent upon current system conditions where during light load conditions Real-time Assessments may not be needed as frequently as they are during peak load conditions. Even this can be different from system to system. Some may encounter congestion during light load periods and others may not. It's too dependent on too many variables. We feel that consideration should be given to situations like this rather than a one-size fits all 30-minute rule.
Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability.. No change made.		
MidAmerican Energy	No	See comments provided under TOP-001.
Response: See response to comments for TOP-001.		
ACES Standards Collaborators	Yes	We understand the rationale for using 30 minutes for performing Real-time Assessments and believe it is sufficient. We ask the SDT to clarify that registered

Organization	Yes or No	Question 12 Comment
		entities are not required to install real-time state estimation to perform its Real-time Assessments.
Response: The Standard does not mandate a specific toolset required to perform a Reliability Assessment.		
Peak Reliability	Yes	Peak Reliability believes this timeframe to be sufficient as long as the 30 minutes is under normal operating conditions (when tools are working as expected). However, IRO-008-2 R5 needs to be revised to include language allowing for tool outages. What is the SDT's expectation of performing Real-Time Assessments when tools are unavailable due to unforeseen tool outages?
Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. The Standard does not mandate a specific toolset required to perform a Reliability Assessment nor does it specify the type of evaluation that has to be performed when tools are unavailable. The SDT expects that some type of evaluation is performed at least every 30 minutes regardless of tool availability. However, the SDT feels that the definition does provide the flexibility needed by the		

Organization	Yes or No	Question 12 Comment
industry to determine the type and manner of evaluation or other procedural backstop process to support a Real-time evaluation even after unforeseen tool failures.		
Independent Electricity System Operator	Yes	We agree with the 30 minute time frame. Further, we suggest the standard be strengthened to ask for developing SOLs and IROLs within 30 minute if there does not exist any predetermined or valid limits for the conditions being analyzed. This is particularly important when, for example, an entity has valid SOLs and IROLs for a set of system and operating conditions but an unplanned event that takes out some BES Facilities from service, rendering the previously developed SOLs/IROLs not valid. In this case, the responsible entity needs to recalculate the SOLs/IROLs for the new condition. A 30-minute is the appropriate time frame for the recalculation. The standard should specifically require that SOLs/IROLs be reestablished within this period.
Response: The SDT believes that operation to SOL/IROL(s) should be inherent to any Real-time Assessment process. However, the SDT feels that mandating the development of SOL/IROL(s) under outage conditions is better addressed as part of the SOL Methodology and the requirement to ensure BES performance consistent with approved FAC-011-2. The proposed definition/requirement does not prohibit an entity from developing SOL/IROL(s) in real-time based on unplanned events. No change made.		
Northeast Power Coordinating Council		30 minutes is appropriate and consistent with the current NERC EAP guidelines for monitoring and control functionality under normal operating conditions. However, exceptions need to be afforded for EMS system failures and unplanned Control Center outages and/or evacuations, or system blackout, e.g., Hurricanes Katrina, Ike, and Sandy, 2003 Northeast Blackout, 2012 Southwest Blackout. See EOP-004-2 - Attachment 1, Standard EOP-008-1 - Loss of Control Center Functionality, Standard COM-001-2 - Communications (R9), Standard EOP-005-2 - System Restoration from Blackstart Resources, Standard EOP-008-1 - Loss of Control Center Functionality.
Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-		

Organization	Yes or No	Question 12 Comment
3. Based on the current standards in place, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity's Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. The definition of Real-Time Assessment provides flexibility and allows for other types of evaluation methods for periods where normal tools are unavailable or during EMS failures. The SDT feels that is important for entities to recognize the need for situation awareness even during periods where primary monitoring systems are unavailable.		
Dominion		Dominion believes that the required periodicity for the performance of Real-time Assessments should be at least once every ten minutes. This is the periodicity that

Organization	Yes or No	Question 12 Comment
		NERC required MISO and First Energy to meet following the August 14, 2003 blackout. See page 152 of the Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004
Response: The SDT does not agree with increasing the required periodicity to 10 minutes. The SDT believes that the 30-minute Reliability Assessment timing requirement is a minimum requirement during normal operations and is intended to accommodate the different types of operating models within the industry while promoting consistent monitoring practices across the Interconnections. The proposed requirement does not prohibit entities from performing more frequent analysis as system conditions warrant. The SDT expects that some entities do, and will continue to, perform assessments on a more frequent basis depending on the systems and potential impacts to BES reliability. No change made.		
Idaho Power		The 30 minute time seems to be an arbitrary value. Real-time Assessments need to be done as system conditions change; load or interchange changed by XXX MW's or system topology changes would seem to be a more logical trigger. That said a specific time frame of 30 minutes, 45 minutes or 1 hour would be easier to audit. Inaccurate assessments that have been rushed in order to meet a compliance standard can have extreme adverse impact on reliability.
Response: The SDT recognizes the concern that depending on the toolset, the level of effort to perform a Real-time Assessment could be impacted by the magnitude of the changes to system conditions. The effort required to perform a Real-time Assessment during timeframes with minimal change may be nothing more than reviewing/updating a previous Real-time Assessment. The SDT feels that is important for entities to recognize the need for situation awareness during all operating periods. Processes must be established to ensure Real-time Assessments are accurate, especially during timeframes of rapidly changing system conditions or sudden topology changes. No change made.		
Oncor Electric Delivery LLC		As previously stated in response to Question 7, Oncor considers Real-time Assessments to be a Reliability Coordinator function. The 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. Requiring Transmission Operators to replicate Real-time Assessments currently performed by the Reliability Coordinator (ERCOT) creates added expense and contributes no added

Organization	Yes or No	Question 12 Comment
		reliability to the BES. Oncor requests the SDT consider the applicability before responding to the periodicity.
Response: The SDT did discuss implications of the applicability; however it found that the definition is consistent with currently approved requirements for Transmission Operators. As an example, approved TOP-004-2 requires Transmission Operators to ensure that the transmission system is operated so that instability, uncontrolled separation, or Cascading outages will not occur as a result of the most severe single Contingency. A Real-time Assessment must be performed to ensure BES facilities are N-1 secure. No change made.		
Texas Reliability Entity		SDT, please consider that a different periodicity may be required depending on the tools used to perform Real-time Assessments. In the ERCOT region, some of the tools used for performing Real-time Assessments only run once every 30 minutes. Since SOLs, by definition, include voltage and transient stability ratings, this implies that the stability analysis should be conducted at least once every 30 minutes. If the tool fails to solve or fails to converge during one of these runs, would that constitute a violation of this requirement? If State Estimator or Contingency Analysis tools are unavailable for 30 minutes or more (i.e. currently a reportable event under the NERC Events Analysis program category 1h), would that constitute a violation of this requirement?
Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3 Based on the current standards in place, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The definition/requirement does not mandate the specific toolset or process to perform the evaluation and therefore allows entities flexibility in how an evaluation is performed given the potential operating scenarios and/or normal monitoring tool failures. No change made. The SDT is not permitted to respond to questions about potential compliance.		

Organization	Yes or No	Question 12 Comment
Arizona Public Service Company	Yes	We agree with the 30 minute periodicity
FRCC Operating Committee (Member Services)	Yes	
Colorado Springs Utilities	Yes	No Comments
CenterPoint Energy Houston Electric LLC.	Yes	CenterPoint Energy agrees with 30 minutes being the correct periodicity for performing Real-time Assessments.
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Seminole Electric Cooperative, Inc.	Yes	Seminole agrees with 30 minutes
Xcel Energy	Yes	
American Transmission Company	Yes	ATC has no comment whether 30 minutes is the correct periodicity for the performance of Real-time Assessments for Reliability Coordinators and Transmission Operators.
David Kiguel	Yes	Agree with the 30 minutes periodicity.
Consumers Energy	Yes	
Hydro One	Yes	

Organization	Yes or No	Question 12 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Salt River Project	Yes	
Florida Municipal Power Agency		FMPA agrees with 30 minutes as a minimum periodicity for Real-time Assessments.
Response: Thank you for your response.		

13. Do you have any comments on the SOL Exceedance White Paper? If so, please provide technical rationale for your disagreement along with suggested language changes.

Summary Consideration: Most of the comments were requesting clarification on a specific item or term or suggesting slight changes to provide additional clarification. Changes were made to the SOL whitepaper to address industry comments. A red-lined version of the whitepaper is available as a separate document on the project web site.

Organization	Yes or No	Question 13 Comment
Northeast Power Coordinating Council	Yes	The SOL Whitepaper provides a good example of evaluating system performance. However, it implies that the continuous thermal rating is a hard limit. A Rating Authority may establish applicable pre-contingency thermal limits that are higher than the continuous rating under specific circumstances and do not result in equipment damage. The acceptable pre-contingency performance defined on page 2, item (b) can be written as "All Facilities shall be within their pre-Contingency thermal limits" rather than "All Facilities shall be within their Normal (continuous) Facility Ratings and thermal limits." This is consistent with the methodology for voltage limits listed on page 2, item (c).From an operational perspective, it is not practical to cover any and all unit instability issues which may remain local in nature. We agree that, to the extent unit instability would cascade into system instability, operating plans must protect against that. Operationally you need to protect against the loss of units regardless of cause.
Response: The SDT chose to retain the "Normal" limit to ensure consistency with approved FAC-008-3. The whitepaper use of the term "instability" is consistent with the NERC definition of SOL as well as approved FAC-011-2 for the operations horizon, which requires all applicable entities to demonstrate transient, dynamic, and voltage Stability following defined Contingencies. The SDT struck the parenthetical "continuous" language throughout the whitepaper.		
ACES Standards Collaborators	Yes	(1) If the drafting team has identified "much confusion with - and many widely varied interpretations and applications of - the SOL term," then why not revise the definition of SOL in the NERC glossary? The whitepaper provides clarification, but this

Organization	Yes or No	Question 13 Comment
		document may be lost over time. We recommend that the drafting team discuss revisions to the glossary term to determine if additional clarity can be provided.
Response: The SDT considered modifying the existing SOL definition but came to the conclusion that the definition could not be modified in a concise manner. The SDT believed that a better approach would be to provide a whitepaper including examples. The SDT intends to incorporate industry comment into the whitepaper and incorporate the whitepaper as an Appendix to proposed TOP-001-3. The SDT encourages the industry to pursue redefining SOL and IROL through the SAR process if it is deemed necessary or appropriate. No change made.		
ISO/RTO Standards Review Committee (SRC)	Yes	From an operational perspective, we do not believe it is practical to cover for any and all unit instability issues which may remain local in nature. We agree that, to the extent unit instability would cascade into system instability, operation plans must protect against that. We also have a concern over the actions depicted for the Emergency (4 hr.) condition in the example in Table 1.When power flow on a Facility exceeds the 4-hour rating, an entity would take all available actions except load shedding to reduce flow to below the 4-hour rating. If the projected loading exceeds the Emergency rating of the concerned (limiting) Facility, load shedding may not be implemented but rather, can be implemented when the critical contingency occurs providing that the load shedding action can be implemented with the time on which the applicable emergency rating is based (e.g. 30 or 15 minutes) to reduce flow within the applicable rating. In other words, an entity may not shed load for the sake of avoiding shedding load if and when a contingency occurs. We suggest to revise the example to: All of the above, plus load shed as necessary and appropriate, to control violation below Emergency rating consistent with timelines identified in Operating Plan. The “as necessary and appropriate” qualifier will allow and entity to assess if load shedding post-contingency can be implemented in time to avoid exceeding the Emergency rating.

Organization	Yes or No	Question 13 Comment
Response: The whitepaper use of the term "instability" is consistent with the NERC definition of SOL as well as approved FAC-011-2, which require all applicable entities to demonstrate transient, dynamic, and voltage Stability following defined Contingencies. No change made. The SDT agrees and has modified the whitepaper to include the qualifier "as necessary and appropriate". See redlined whitepaper for revisions.		
Peak Reliability	Yes	Comment 1 - the SOL performance summary states that it is acceptable to operate above the highest available limit post-contingency as long as "the entities operating plan address potential impacts and mitigating strategies to ensure potential impact is localized." Post-contingency exceedance of the highest available limit should not be allowed unless there are no viable pre-contingency actions short of load shed, AND the impact of the contingency is known to be contained. Comment 2 - Operating plan example table uses the term "load shed" to describe a facility rating. This sounds like it came from Alstom data base naming conventions, but may result in confusion and should be changed.
Response: The SDT agrees that "Post-contingency exceedance of the highest available limit should not be allowed unless there are no viable pre-contingency actions short of load shed and the impact of the contingency is known to be contained." The SDT has provided clarification within the whitepaper. See redlined whitepaper for revisions. Approved FAC-008-3 allows for more than one "Emergency Rating". The SDT modified the whitepaper to remove "Load Shed" rating to ensure terminology consistent with approved FAC-008-3. See redlined whitepaper for revisions.		
Bonneville Power Administration	Yes	Since entities will need to accurately interpret several requirements in the Standard, BPA suggests adding the System Operating Limit (SOL) Definition and Exceedance Clarification white paper to the TOP-001-3 Standard as an appendix.
Response: The SDT intends to add the whitepaper as an appendix to the proposed TOP-001-3.		

Organization	Yes or No	Question 13 Comment
CenterPoint Energy Houston Electric LLC.	Yes	At a high level, CenterPoint Energy supports the SOL Exceedance White Paper; however, the Company has concerns regarding two main issues identified below. 1) SOL Performance Summary Chart (Page 4): The ERCOT Region operates such that the continuous Pre-Contingency flow never exceeds the 24hr rating. For reliability purposes, CenterPoint Energy believes Pre-Contingency flow in any range above the 24hr rating is not acceptable and recommends the SDT revise the chart accordingly. 2) Steady State Voltage Limit Exceedance (Page 5): The second sentence states, "Both normal and emergency voltage limits are established that respect the Transmission Owner or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3." CenterPoint Energy does not agree that normal and emergency voltage limits are established using the Facility Ratings Methodology required in FAC-008-3. For example, FAC-008-3 R8.2 refers specifically to a Thermal Rating. Additionally, the NERC definitions of Normal and Emergency Ratings refer to "electrical loading, usually expressed in megawatts..." which indicates a Thermal Rating. While CenterPoint Energy agrees that normal and emergency voltage limits are established, it is through other means outside of FAC-008-3; therefore, CenterPoint Energy recommends removing this sentence.
Response: The chart is indicative of minimum acceptable system performance. While entities may choose to adopt a more rigorous approach to pre-Contingency exceedance of Facility Ratings, the SDT believes that the minimum level of acceptable pre-Contingency performance occurs when a Facility Rating is exceeded for an unacceptable time duration – not when it is exceeded at all. An entity's Operating Plan addresses scenarios when Load shed is required pre-Contingency. No change made. The NERC definition of Facility Rating includes "maximum and minimum voltage". The SDT believes that approved FAC-008-2 does not prevent Transmission Owners and Generator Owners from including voltage limitations within the scope of the Facility Ratings Methodology document if the Transmission Owner or Generator Owner chooses to do so. Approved FAC-008-2 frequently speaks to "equipment ratings" and "manufacturer's specifications", which can include voltage limitations. If a Transmission Owner or Generator Owner's Facility Ratings Methodology includes voltage limitations, then the voltage limits determined by the Transmission Operator need to respect those limitations. The SDT did not remove the reference to the Transmission Owner's and Generator Owner's Facility Ratings Methodology with reference to voltage limits; however, the SDT did change the language to say: "Normal		

Organization	Yes or No	Question 13 Comment
and emergency voltage limits are expected to respect any voltage limitations specified in the Transmission Owner or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3." See redlined whitepaper for revisions.		
Volkmann Consulting	Yes	Figure 1 on page 4 suggests that the TOP is allowed to risk a post contingency exceedance of the short term emergency (STE) rating if there is an Operating Plan. This is a dangerous reliability risk. An Operating Plan should not be an acceptable means to exceed the STE, unless that Transmission Owner's Facility Rating Methodology allows it and agrees to a new STE. The new STE must factor in the response time of the Operating Plan. As stated the document suggests that the Operating Plan can be used with no limitations of exceeding the STE.
Response: The SDT agrees. However, the SDT does not want to set the expectation that Load must be shed pre-Contingency whenever tools indicate an operating condition where a Contingency will cause a Facility to exceed its STE. While the SDT expects entities to take pre-Contingency steps to relieve the condition (including re-dispatch, reconfiguration, and making adjustments to the uses of the Transmission system), the issue of "when to shed Load pre-Contingency" is expected to be addressed in the Operating Plan. An entities Operating Plan will define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure, consistent with the purpose of SOL Methodologies. The SDT has provided additional clarification within the whitepaper. See redlined whitepaper for revisions.		
David Kiguel	Yes	Intent is correct. Could better explain some concepts like for example when short time ratings could be exceeded in pre-contingency.
Response: The SDT has revised the whitepaper to provide additional clarification on this topic. See redlined whitepaper for revisions.		
Electric Reliability Council of Texas, Inc.	Yes	Table 1 identifies trending/monitoring and non-cost actions to prevent contingency from exceeding emergency limit. Some entities may only alarm/trend/monitor when post-contingency loading approaches within a threshold or exceeds the emergency limit. This minimizes unnecessary attention to post-contingency loading that an operator has sufficient time to reduce loading if the contingency were to occur. Transient instability (angular, un-damped oscillations) can be in addition to voltage instability, be local instability limits and not qualify as an IROL.

Organization	Yes or No	Question 13 Comment
Response: The SDT agrees with the assessment of alarm/trend/monitor, however, the SDT encourages entities to alarm at a threshold below the emergency limit to ensure System Operators have sufficient time to proactively address facility loadings. The SDT agrees that IROL facilities are a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s), or cascading outages and are not localized in nature. No change made.		
PNMR		Figure 2 of the whitepaper depicts a PV plot and is used to demonstrate the definition of an IROL. PNMR finds this figure to be confusing. The figure defines the IROL as the "knee" on the PV plot. In WECC the path SOL may be a value less than the "knee" of a PV curve. Does the figure imply that all voltage stability SOLs also have an IROL? Can only path voltage stability and voltage SOLs have IROLs? PNMR would recommend clarifications be added to the whitepaper to resolve these questions.
Response: While the SDT cannot comment on WECC specific concepts such as the "path SOL", the SDT believes that SOL exceedance is generally characterized by the exceedance of Facility Ratings or voltage limits. To the extent that exceeding an SOL could result in wide-area impacts such as cascading, uncontrolled separation, or uncontained instability, that facility would also have an IROL. The SDT does not believe that all Stability issues are automatically IROLs. As stated in the whitepaper, a localized voltage collapse may not qualify as an IROL. No change made.		
Independent Electricity System Operator	No	We generally agree with the White Paper except the actions depicted for the Emergency (4 hr.) condition in the example in Table 1.When power flow on a Facility exceeds the 4-hour rating, an entity would take all available actions except load shedding to reduce flow to below the 4-hour rating. If the projected loading exceeds the Emergency rating of the concerned (limiting) Facility, load shedding may not be implemented but rather, can be implemented when the critical contingency occurs providing that the load shedding action can be implemented with 15 minutes or less to reduce flow within the 15-minute or 4-hour rating. In other words, an entity may not shed load for the sake of avoiding shedding load if and when a contingency occurs. We suggest to revise the example to: All of the above, plus load shed as necessary and appropriate, to control violation below Emergency Rating consistent with timelines identified in Operating Plan. The "as necessary and appropriate"

Organization	Yes or No	Question 13 Comment
		qualifier will allow and entity to assess if load shedding post-contingency can be implemented in time to avoid exceeding the 15-minute rating.
Response: The SDT has revised the whitepaper to include "as necessary and appropriate". See redlined whitepaper for revisions.		
Duke Energy	No	1. Duke Energy disagrees with the idea that every exceedance of a facility rating is an SOL(s) as indicated in the White Paper. We would also like to point out that this premise is not reflected in the currently enforceable Reliability Standards. Also, it appears as though the authors of the White Paper may have inadvertently over-complicated their explanation of what constitutes an SOL. We believe that the use of the term "actual flow" in place of Pre-Contingency would help improve the clarity of the examples given throughout the White Paper. 2. Figure 1 on page 4: The table appears to be more restrictive at lower loading levels than it is at higher loading levels, and it also appears to be in conflict with the Operating Plan found on the next page with regard to Load Shedding. 3. We also suggest adding language stating, that "unless the entity's Operating Plan addresses potential impacts and mitigating strategies to ensure potential impact is localized" at the end of the fourth and sixth bullets in Figure 1, this would improve the consistency. 4. Steady State Voltage Limit Exceedance: We suggest striking the "or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event" from the paragraph. We feel that there could be auto-reactive supplies that may be available to bring the limit back to an acceptable range, also, a Real-time Assessment/situational awareness tool is designed to aid in managing the system and not designed to create exceedances and violations. 5. Also, we suggest that a clause be inserted taking into account automatic or manual control of reactive resources that are accepted per FAC-011 for SOL(s). Ultimately, we feel that SOL performance is based on flows in Real-time, and that is the criteria that should be used to determine if you have exceeded or not exceeded.

Organization	Yes or No	Question 13 Comment
		6. Stability Limit Exceedance: The first sentence of paragraph 4 which states, "SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability" appears to redefine what is considered an SOL exceedance. An SOL is supposed to have a value associated with it, and you exceed the SOL when you cross that value. The above referenced sentence describes an SOL exceedance as entering into an Operating space and then what the next contingency could result in. We feel that this language is not consistent with the definition of an SOL. 7. Figure 2: Duke Energy is concerned that the language in Figure 2 is expanding the concept of SOL Exceedance. Of particular concern is the phrase, "unacceptable system performance equates to SOL exceedance," we fail to see how one could monitor this or even apply it. 8. Also, we recommend the removal of bullets 2 and 4. It appears that bullet 4 is saying the same thing regarding voltage, as bullet2 is saying for facility ratings. 9. Lastly, bullets 1 and 3 are not "Assessments." We suggest them being in their own category, as SOL exceedance should be based on actual system conditions 10. SOL Exceedance and Operating Plan: Duke Energy is concerned that the language used in this section blurs the line on whether you have exceeded an SOL or not. As currently written, the section reads as though that even after you have exceeded an SOL, it may depend on what happens afterward to determine if it was an actual exceedance or not. With the actual exceedance in doubt, it is difficult to know where an entity is from a compliance standpoint. . 11. Table 1 Operating Plan Example: We request removal and replacement of the terms "Non-Cost" and "Off-Cost" with more common industry terms, or insert an explanation of the terms used. Also, the use of the terms "load shed" in the Pre- and Post-Contingency Loading columns is somewhat misleading. Consider revising to more clearly state the expectations regarding the use of Load Shed in this context.

Organization	Yes or No	Question 13 Comment
		Applicable Definitions: The term "Interchange" is used sporadically throughout the definitions section of the White Paper, we suggest changing to "known Interchange" for clarity. Also, we recommend removing the parenthetical at the end of Real-time Assessment and Operational Planning Analysis. Lastly, Phase Angle, Equipment Limitations, and Special Protection System should be listed as sub bullets as part of the Assessment, and not be a part of the definition.

Response:

1. The whitepaper attempts to clarify long-standing points of confusion – understanding what an SOL is, what it means to establish an SOL, and what it means to exceed an SOL by pointing directly to requirements contained within the approved FAC Standards. The SDT believes so long as Transmission Operators are following approved FAC-014-2, Requirement R2, there will be no inconsistencies between Reliability Coordinator and Transmission Operator monitored SOLs (page 2, bullet 3 of whitepaper). Individual Operating Plans, that recognize time-based rating methodologies, provide guidance to System Operators to ensure SOL exceedances are mitigated. No change made.
2. The SDT has reviewed the figure and table and does not agree with Duke's assertions. Figure 1 on page 4 is less restrictive at lower load levels and more restrictive at higher load levels as indicated by the decreasing mitigation time requirements as loading increases. The SDT made changes to the body of the whitepaper and to the second bullet in Figure 1, to address the Load shed issue. The revised whitepaper states that "An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring BES remains N-1 secure."
3. The SDT believes the bullets are correct and complete. Duke's suggested language applies only to the second bullet and does not apply to the 4th and 6th bullets. The Operating Plan should reflect whether pre- or post-Contingency action is required based the time based Facility Rating, available mitigation actions, the amount of time System Operators have to implement those actions. The whitepaper clarifies this issue with the added statement, "In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, Transmission Operators are expected to take pre-Contingency action to relieve the condition (including re-dispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition.
4. The SDT believes that Real-time Assessments aid the System Operators in managing the system by determining whether or not SOLs are being exceeded in Real-time operations. It is common practice to have auto- reactive devices which ensure acceptable post-Contingency voltages. The SDT sees no conflict so long as the Real-time Assessment recognizes the impact of auto-reactive

Organization	Yes or No	Question 13 Comment
devices and those devices are sufficient to maintain voltages within acceptable limits. The SDT added the concept of auto-reactive devices as part of an assessment in determining SOL exceedances as per Duke's request. **5.** The SDT agrees that SOL performance is based Real-time flows and voltages, but considers both the pre- and post-Contingency operating states. This is described in the whitepaper. No change made. **6.** The SDT does not agree with Duke's comment. The SDT basis for the whitepaper was the NERC definition of SOL (first paragraph) and used the subsequent paragraphs of the whitepaper to tie various standard Requirements together in an effort to further define SOL exceedance for each component (thermal, voltage and stability). One component, Stability limits, are typically developed during the Operating or Planning Horizon, though they can also be determined in Real-time. Stability limits and mitigating strategies are provided to System Operators as part of an Operating Plan. Real-time Assessments are performed to ensure the system is operated in a state where the next Contingency does not result in instability (i.e., no SOL exceedance). No change made. **7.** The SDT believes the bullets that follow Figure 2 further define "unacceptable performance" or "SOL Exceedance" and that additional details would be contained within the entities Operating Plan, which provides System Operators details on how to monitor and mitigate potential SOL exceedances. No change made. **8.** The SDT chose to include separate bullets to clearly explain unacceptable performance for both pre- and post-Contingency thermal and voltage scenarios. No change made. **9.** The SDT chose to include separate bullets to clearly explain unacceptable performance for both pre- and post-Contingency thermal and voltage scenarios. A Real-time Assessment includes an analysis of actual flows/voltages even though the system may be more frequently limited on an N-1 basis. No change made. **10.** The SDT considered Duke's comments but were cautious of developing a "one size fits all" approach. The whitepaper intends to clarify when an SOL is being exceeded. The revised TOP standards requires System Operators take action to mitigate an SOL exceedance in accordance with their Operating Plan. The System Operators should follow the details of that entities Operating Plan to ensure that an exceedance does not result in a violation. No change made. **11.** The SDT has revised the whitepaper to provide additional clarification where required. See redlined whitepaper for revisions.		
SPP Standards Review Group	No	We have concerns with the implications in the last paragraph on Page 2. The implication here is that a set of SOLs defined at some previous time may not be adequate to protect the reliability of the BES. We agree with this concept but believe the white paper needs to recognize the fact that the list of SOLs may not necessarily be stagnant. If this pre-defined listing is updated continuously in Real-time, it is a very

Organization	Yes or No	Question 13 Comment
		accurate representation of the limitations on the system at any given time. The white paper doesn't provide for this additional concept and should. Capitalize 'Real-time' in the 1st bullet at the top of Page 9. Also capitalize Bulk Electric System in the 2nd bullet. Delete the comma in the last line of the definition of Emergency Rating.
Response: The SDT agrees that SOLs are not stagnant and will change over time. The intent of the whitepaper is to provide clarity across the Interconnections, while still respecting that an individual entities SOL Methodology provides details that recognize the complexities of a regional electric grid. The SDT has revised the whitepaper to provide additional clarity. Additionally, the SDT has incorporated the suggested grammatical changes. See redlined whitepaper for revisions.		
FRCC Operating Committee (Member Services) Florida Municipal Power Agency Seminole Electric Cooperative, Inc.	No	Add language to the SOL Exceedance White Paper to state that a SOL can only be exceeded where it has been defined on a TOPs system as is stated in FAC-014-2. Add language to the SOL Exceedance White Paper clarifying that SOLs are only exceeded in Real-time based on actual system conditions and not as a result of the use Real-time assessment tools performing post-contingency analysis. Page 3 - Change the words "SOLs include Facility Ratings..." to "SOLs may be based on Facility Ratings..." Page 4 - SOL Performance Summary bullet 4. Add language "except load shed" to be consistent with operating plan in table 1. Page 8 - Typo in the Operating Procedure definition. The word "operating" should be "operator" in the last sentence.
Response: 1. The SDT believes that as long as Transmission Operators are following approved FAC-014-2, Requirement R2, there will be no inconsistencies between Reliability Coordinator and Transmission Operator monitored SOLs (page 2, bullet 3 of whitepaper). The SDT added language to clarify that SOL exceedance is based on Real-time Assessments.		

Organization	Yes or No	Question 13 Comment
2. The SDT believes that SOL exceedance is based on pre- or post-Contingency conditions, consistent with the acceptable system performance criteria described in approved FAC-011-2 Requirement R2. As stated in the whitepaper, unacceptable pre- or post-Contingency performance (as described in approved FAC-011-2 Requirement R2) equates to SOL exceedance. No change made. 3. The SDT agrees and has revised the whitepaper accordingly. See redlined whitepaper for revisions. 4. The SDT has revised the whitepaper to provide clarity on the Load shed issue. See redlined whitepaper for revisions. 5. The SDT has revised the whitepaper to address the grammatical error. See redlined whitepaper for revisions.		
Consumers Energy	Yes	
Dominion	Yes	Dominion would like to state its support and agreement with this well written paper.
PacifiCorp	No	
Arizona Public Service Company	No	
Associated Electric Cooperative, Inc. - JRO00088	No	
MRO NERC Standards Review Forum	No	
Colorado Springs Utilities	No	
SERC OC Review Group	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi	No	

Organization	Yes or No	Question 13 Comment
Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
PPL NERC Registered Affiliates	No	
Georgia System Operations	No	
EDP Renewables North America LLC	No	
Manitoba Hydro	No	
Xcel Energy	No	
American Transmission Company	No	
Idaho Power	No	
PJM Interconnection	No	
Liberty Electric Power, LLC	No	
Oncor Electric Delivery LLC	No	
Tri-State Generation and Transmission Association, Inc.	No	

Organization	Yes or No	Question 13 Comment
INDN - Independence Power & Light	No	
Georgia Transmission Corporation	No	
Salt River Project	No	
MidAmerican Energy	No	
Response: Thank you for your response.		

14. The SDT has made revisions to VRFs and VSLs as needed to conform to changes made to requirements. Do you agree with the VRFs and VSLs for the nine posted standards? If you do not agree, please indicate specifically which standard(s) and requirement(s), and whether it is the VRF or VSLs you disagree with, and explain why.

Summary Consideration: The SDT made a number of changes due to industry comments.

Proposed IRO-001-4, Requirement R3, Severe VSL: The responsible entity failed to inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R2 citing one of the reasons shown in Requirement R2.

Proposed IRO-002-4, Requirement R2:

R2	Operations Planning, Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not have data exchange capabilities with one applicable entity, or 5% or less of the applicable entities, whichever is less.	The Reliability Coordinator did not have data exchange capabilities with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is less.	The Reliability Coordinator did not have data exchange capabilities with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is less.	The Reliability Coordinator did not have data exchange capabilities with four or more applicable entities or greater than 15% of the applicable entities, whichever is less.

Proposed IRO-008-2: Data Retention - Each Reliability Coordinator shall each keep data or evidence for Requirement R5 and Measure M5 for a rolling 30 day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Proposed IRO-008-2, Requirement R1, Severe VSL: The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Reliability Coordinator will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs).

Proposed IRO-008-2, Requirement R5:

IRO-008-2, R5	Real-time Operations	High	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	The Reliability Coordinator did not perform Real-time Assessments. OR For any sample 24 hour period within the 30 day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for more than three 30-minute periods within that 24-hour period.

Proposed IRO-008-2, Requirement R7, Severe VSL: The Reliability Coordinator failed to issue Operating Instructions, as necessary, to ensure that actions were taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.

Proposed IRO-008-2, Requirement R8:

R8	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit (SOL) or Interconnection	The Reliability Coordinator did not notify two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit	The Reliability Coordinator did not notify three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit	The Reliability Coordinator did not notify four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6

			Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan when the Emergency identified in Requirement R6 was prevented or mitigated	(SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement	(SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement	was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated.

				R6 was prevented or mitigated	R6 was prevented or mitigated	

Proposed IRO-010-2, Requirement R1: The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: (Violation Risk Factor: Low) (Time Horizon: Operations Planning)

Proposed IRO-010-2, Requirement R1, Severe VSL (first part): The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Proposed IRO-010-2, Requirement R2: The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. (Violation Risk Factor: Low) (Time Horizon: Operations Planning)

Proposed IRO-010-2, Requirement R2, VSL Table: For the Requirement R2 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.

Proposed IRO-010-2, Requirement R3:

R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented	The responsible entity receiving a data specification in Requirement R2 did not satisfy the obligations of the

			specifications for data but failed to follow one of the criteria shown in Parts 3.1 – 3.3.	specifications for data but failed to follow two of the criteria shown in Parts 3.1 – 3.3.	specifications for data but failed to follow any of the criteria shown in Parts 3.1 – 3.3.	documented specifications for data.

Proposed IRO-014-3, Requirement R2:

R2	Operations Planning, Same-Day Operations	Lower	N/A	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet one of the criteria specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet two of the criteria specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet all three of the criteria specified in Requirement R2.

Proposed IRO-014-3, Requirement R6, Severe VSL: The Reliability Coordinator failed to operate as though the Emergency existed during an instance where Reliability Coordinators disagreed on the existence of an Emergency.

Proposed IRO-017-1, Requirement R1:

R1	Operations Planning	Medium	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing one of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing two of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing three of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing four or more of the parts specified in Requirement R1 (Parts 1.1 – 1.4). OR, The Reliability Coordinator did not develop, implement,

						and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Proposed TOP-001-3, Requirement R8:

R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one other known impacted Transmission Operator or 5% or less of the known impacted other Transmission Operators, whichever is less, of its actual or expected operations that	The Transmission Operator did not inform two other known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted other Transmission Operators, whichever is less, of its actual or expected	The Transmission Operator did not inform three other known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted other Transmission Operators, whichever is less, of its actual or	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR

			resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform one other known impacted Balancing Authorities or 5% or less of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions	operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform two other known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas	expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform three other known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on	The Transmission Operator did not inform four or more other known impacted Transmission Operators or more than 15% of the known impacted other Transmission Operators, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform four or more other known impacted Balancing Authorities or more 15% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could

			did permit such communications.	when conditions did permit such communications.	respective Balancing Authority Areas when conditions did permit such communications.	have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.

Proposed TOP-001-3, Requirement R13:

R13	Same-Day Operations, Real-Time Operations	High	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	The Transmission Operator did not perform Real-time Assessments. For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three or more 30-minute periods within that 24-hour period.

Proposed TOP-002-4, Requirement R1, Severe VSL: The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).

Proposed TOP-002-4, Requirement R4, Severe VSL: The Balancing Authority did not have an Operating Plan.

Proposed TOP-003-3, Requirement R3, Severe VSL: The Transmission Operator did not distribute its data specification to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Proposed TOP-003-3, Requirement R5:

R5	Operations Planning, Same-Day Operations Real-time Operations	Medium	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet one of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet two of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet all three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3). OR, The responsible

						entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

Organization	Yes or No	Question 14 Comment
Northeast Power Coordinating Council	No	IRO-008-2: R5 requires a real-time assessment every 30 minutes. The VSL is graduated in 5 minute increments. The VSL does not specify the period being measured. The existing IRO-008-1 utilizes a 24 hour sampling in the existing VSL. A similar approach should be used. Each VSL should be checking the completed assessments in a 24 hour period and that the periodicity was within a time bound. So VSL Low would be: The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than 30 minutes but less than 35 minutes OR for any sample 24 hour period within the 30 day retention period, a Real-time Assessment was not conducted for one 30-minute period within that 24-hour period. IRO-014--In the VSL Table repeat the header row for all pages containing the VSL table. IRO-014 R6 (Severe VSL) : in order to be consistent with other standards, change the tense of the verb "exists" to "existed". IRO-017-- R2 VRFs should be Medium, not Low. This is a performance requirement.

Organization	Yes or No	Question 14 Comment
		TOP-001 R3 thru R6 VSLs--an Operating Instruction applies to both Normal and Emergency operations. Therefore the VSL should be graduated similarly to COM-002-4 R5. OI issued during an Emergency is a Severe VSL and OI issued during Normal events is Moderate VSL. In the VSL Table, for R3 and R5 (Severe VSL), suggest changing the sentence to "The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator when such an action could have been physically implemented and would not have violated safety, equipment, regulatory or statutory requirements." In the VSL Table for R7 (Severe VSL), suggest changing the sentence to "The Transmission Operator or Balancing Authority did not provide assistance to Transmission Operators, if requested, when the requesting entity had implemented its emergency procedures when such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements." In the VSL Table for R8 (all VSL levels) change the tense of the verb "result in" to "resulted in, or could have resulted in ...." to match the rest of the VSL that is written in the same tense. (Extracted from Q1) IRO-001-4: An Operating Instruction applies to both Normal and Emergency operations. Therefore, the VSL should be graduated similar to COM-002-4 R5. OI issued during an Emergency is a Severe VSL and OI issued during Normal events is a Moderate VSL. (Extracted from Q4) IRO-010-2: Similar to TOP-003, R1 and R2 VRFs should be Low, not Medium. (Extracted from Q7) TOP-001-3: Requirement R5 has a zero-defect problem similar to what was argued for COM-002-4. A single instance of a failure to comply with any Operating Instruction results in a severe violation. We recommend a revision to this approach more consistent with the COM-002-4 penalties. A demonstrated pattern of

Organization	Yes or No	Question 14 Comment
		problems would trigger a Severe VSL, but isolated single events, which did not impact the BES, should not be penalized. (It is hard to argue that not following an OI when one can during an Emergency would not be a severe VSL. Graduated levels could be similar to COM-002-4 R5.) FERC has stated that VSLs should be graded. These are not. Further, intent to perform should count in favor of any entity that is unable to implement an Operating Instruction due to a technical or reliability related concerns. (It is hard to argue that not following an OI when one can during an Emergency would not be Severe. Graduated levels could be similar to COM-002-4 R5.)

Response: Proposed IRO-008-2, Requirement R5: The SDT agrees and has adjusted the data retention period and VSLs to correspond with those in approved IRO-008-1. In addition, the SDT has changed the Time Horizon to correspond with that of proposed TOP-001-3, Requirement R13. See summary consideration for revision.

Proposed IRO-014-3: The SDT agrees and has made the required change to incorporate the header on each page of the VSL Table.

Proposed IRO-014-3, Requirement R6: The SDT agrees and has made the suggested change. See summary consideration for revision.

Proposed IRO-017-1, Requirement R2: The SDT agrees and has made the suggested change. See summary consideration for revision.

Proposed TOP-001-3, Requirements R3 through R6: The SDT agrees that Operating Instructions can be issued during both normal and Emergency conditions. However, the requirements intentionally do not differentiate between such conditions. One either complies with the Operating Instruction or one doesn't. Furthermore, the requirements are set up on an individual Operating Instruction basis which leads to an all or nothing evaluation of compliance and thus the binary severe VSL. The SW Outage report showed the importance of following Operating Instructions regardless of the situation. No change made.

Proposed TOP-001-3, Requirements R3 and R5: The SDT does not believe that the suggested change provides any additional clarification. No change made.

Proposed TOP-001-3, Requirement R7: The SDT does not believe that the suggested change provides any additional clarification. No change made.

Proposed TOP-001-3, Requirement R8: The SDT agrees and has made the suggested changes. See summary consideration for revision.

Proposed IRO-001-4: The SDT does not believe that the suggested change provides any additional clarification. No change made.

Organization	Yes or No	Question 14 Comment
Proposed IRO-010-2, Requirements R1 and R2: The SDT agrees and has made the suggested changes. See summary consideration for revision. Proposed TOP-001-3, Requirement R5: The SDT agrees that Operating Instructions can be issued during both normal and Emergency conditions. However, the requirements intentionally do not differentiate between such conditions. One either complies with the Operating Instruction or one doesn't. Furthermore, the requirements are set up on an individual Operating Instruction basis which leads to an all or nothing evaluation of compliance and thus the binary severe VSL. An entity has the opportunity to inform the Balancing Authority of its inability to perform as shown in Requirement R6. No change made.		
SERC OC Review Group Associated Electric Cooperative, Inc. - JRO00088	No	IRO-001-13, R1.3, IRO-008-2 R5. The SERC OC Review Group has concerns that the bandwidth between “lower” and “severe” VSL is only 15 minutes. Low 30 minutes, high VSL 45 minutes) Suggestion: expand bandwidth. (Extracted from Q7) TOP-001-3: In the R13 VSLs, there is concern that the bandwidth between “lower” and “severe” VSL is only 15 minutes. Suggestion: expand bandwidth. See also response on IRO-008-2, question 3 above.

Organization	Yes or No	Question 14 Comment
Response: IRO-001-13, Requirement R1.3: There is no such standard or requirement. The SDT believes this is a typo and has been answered with the response to proposed IRO-008-2. Proposed IRO-008-2, Requirement R5: The SDT has made changes to the VSLs based on other comments that should address your concerns. In addition, the SDT has changed the Time Horizon to correspond to proposed TOP-001-3, Requirement R13. See summary consideration for revision.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
Idaho Power	No	
Response: Without specific comments, the SDT is unable to respond.		
MidAmerican Energy	No	The VRFs and VSLs will need to be adjusted. (Extracted from Q3) IRO-008-2: Additionally, the VRF and VSLs for R5 will require revision to address the two hour timeframe allowed for in EOP-008.
Response: Proposed IRO-008-2, Requirement R5: The SDT has made changes to the VSLs based on other comments that should address your concerns. In addition, the SDT has changed the Time Horizon to correspond with that of proposed TOP-001-3, Requirement R13. See summary consideration for revision.		

Organization	Yes or No	Question 14 Comment
Duke Energy	No	1. As previously stated in TOP-001 R3, the definition of Operating Instruction makes this requirement (and standard as a whole), too broad in nature. The definition of Operating Instruction carries past the parameters of action in an Emergency situation, and includes all actions. To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written. 2. (Extracted from Q1) IRO-001-4: To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written.
Response: Proposed TOP-001-3, Requirement R3: One either complies with the Operating Instruction or one doesn't. Furthermore, the requirements are set up on an individual Operating Instruction basis which leads to an all or nothing evaluation of compliance and thus the binary severe VSL. No change made. Proposed IRO-001-4: No requirement is provided but the SDT believes this comment is addressing the same issue as proposed TOP-001-3, Requirement R3 above and believes that the same response is appropriate. No change made.		
SPP Standards Review Group INDN - Independence Power & Light	No	TOP-001-3 Delete the phrase '...in Severe VSL for Requirement R3 citing one of the specific reasons shown in Requirement R3.' This will make this VSL parallel the Severe VSL of Requirement R6. Either that or add the phrase to the Severe VSL in Requirement R6. Change all the VSLs such that they read: '...that result in, or could result in, an Emergency in those respective Transmission Operator Areas...' The proposed VSLs for Requirement R13 address not completing the Real-time Assessments within a specified time frame. This makes no adhering to the 30-minute criteria a zero-tolerance requirement. Why not use criteria that are more flexible and reflect a measure of up-time for the assessments? For example, Real-time Assessments were completed within more than 98% but less than 100% of the 30-minute windows during a calendar year. The way the VSL is written if one assessment

Organization	Yes or No	Question 14 Comment
		is not completed within 30 minutes, the entity is just as guilty as if none of the assessments are completed. TOP-002-4Change 'will exceed' in the Severe VSL for Requirement R1 to 'exceeded'. Change 'does' in the Severe VSL for Requirement R4 to 'did'. TOP-003-3Capitalize 'Real-time' in the Severe VSL for Requirement R3. We suggest adding the phrase 'as specified in Requirement R5' at the end of the Severe VSL for Requirement R5. IRO-001-4Use a lower case 'issued' in the Severe VSL for Requirement R3. IRO-008-2Replace 'have an' with 'perform' in the Severe VSL for Requirement R1. The requirement calls for the Reliability Coordinator to perform an Operational Planning Assessment, not to have an assessment. Add the phrase 'in Requirement R2' at the end of the Severe VSL for Requirement R3. Rather than tie compliance to the timing of a single Real-time Assessment in the VSLs for Requirement R5 making this a zero-tolerance requirement, we recommend that the SDT use a performance based, on-time criterion. For example, the Lower VSL could be The Reliability Coordinator performed a Real-time Assessment at less than 100% of the time but more than 98% of the time. The Moderate, High and Severe VSLs would be adjusted in a similar manner. We recommend the Moderate, High and Severe VSLs for Requirement R6 begin with 'The Reliability Coordinator did not notify a total of X impacted Transmission Operators or Balancing Authorities...' A similar change needs to be made for the Moderate, High and Severe VSLs for Requirement R8 except that the 'or' is already used there. Replace 'are' with 'were' in the Severe VSL for Requirement R7. Replace the 'has been' with 'was' in all the VSLs for Requirement R8.

Organization	Yes or No	Question 14 Comment
		IRO-010-2Capitalize Part in the Lower, Moderate and High VSLs for Requirement R3. IRO-014-3Replace 'failed to' with 'does not' in the Severe VSL for Requirement R1. Add the phrase 'specified in Requirement R2' at the end of the Lower, Moderate and High VSLs for Requirement R2. Insert 'has the' between 'Coordinator' and 'Operating Procedures' in the Moderate VSL for Requirement R2. Insert 'the' between 'has' and 'Operating Procedures' in the Moderate VSL for Requirement R2. Insert 'all' between 'meet' and 'three' in the Moderate VSL for Requirement R2. Replace 'does' with 'did' in the Severe VSL for Requirement R2. Aren't the Severe VSLs for Requirements R1 and R2 identical and therefore creating a double jeopardy situation? Insert 'as specified in Requirement R3' between 'Coordinators' and 'in' in all the VSLs for Requirement R3. Replace 'the problem' with 'an Emergency' in the Severe VSL for Requirement R6. Replace the Severe VSL for Requirement R9 with the following: 'The Reliability Coordinator did not provide assistance to a requesting Reliability Coordinator that had implemented its emergency procedures and such actions could have been physically implemented or would not have violated safety, equipment, regulatory, or statutory requirements.'

Organization	Yes or No	Question 14 Comment
Response: Proposed TOP-001-3, Requirement R3: The indicated phrase does not appear in the VSL. Proposed TOP-001-3: No requirement was provided but the SDT believes the comment is with respect to Requirement R8. The SDT agrees and has made the suggested change. See summary consideration for revision. Proposed TOP-001-3, Requirement R13: The SDT has changed the data retention and VSLs for this requirement in order to correspond with those for approved IRO-008-1 and believes that this will address your concerns. See summary consideration for revision. Proposed TOP-002-4, Requirement R1: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed TOP-002-4, Requirement R4: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed TOP-003-3, Requirement R3: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed TOP-003-3, Requirement R5: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-001-4, Requirement R3: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed IRO-008-2, Requirement R1: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed IRO-008-2, Requirement R3: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-008-2, Requirement R5: The SDT has changed the data retention and VSLs for this requirement in order to correspond with those for approved IRO-008-1 and believes that this will address your concerns. In addition, the SDT has changed the Time Horizon to correspond with that of proposed TOP-001-3, Requirement R13. See summary consideration for revision. Proposed IRO-008-2, Requirement R6: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-008-2, Requirement R8: The SDT does not believe that the suggested change adds any clarity. No change made.		

Organization	Yes or No	Question 14 Comment
Proposed IRO-008-2, Requirement R7: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed IRO-008-2, Requirement R8: The SDT agrees and has made the suggested changes. See summary consideration for revision. Proposed IRO-010-2, Requirement R3: The SDT agrees and has changed the VSLs accordingly. See summary consideration for revision. Proposed IRO-014-3, Requirement R1: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-014-3, Requirement R2: The SDT agrees and has changed the VSLs accordingly. These changes should eliminate your concerns about possible double jeopardy. See summary consideration for revision. Proposed IRO-014-3, Requirement R3: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-014-3, Requirement R6: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-014-3, Requirement R9: The SDT does not believe that the suggested change adds any clarity. No change made.		
ACES Standards Collaborators	No	(1) As mentioned in earlier comments, there are several instances in the standards where binary treatment is made to the VSL table where graduated violations could be implemented. (2) In regard to VRFs, we question the need for any requirement that has a low risk factor. We ask the SDT to review the Low VRF requirements to determine if these tasks truly impact reliability. (3) (Extracted from Q1) IRO-001-4: We question the binary nature of the VSL tables and ask the SDT to consider graduated treatment of violations.

Organization	Yes or No	Question 14 Comment
		(4) (Extracted from Q2) IRO-002-4: We question the binary nature of the VSL tables and ask the SDT to consider graduated treatment of violations.
Response: (1) The SDT has responded to all specific requests regarding binary treatment of VSLs. (2) The SDT reviewed all of the VRF assignments. Those requirements assigned a Lower VRF have been deemed as necessary for reliability and not simply administrative tasks. (3) Proposed IRO-001-4: One either complies with the Operating Instruction or one doesn't. Furthermore, the requirements are set up on an individual Operating Instruction basis which leads to an all or nothing evaluation of compliance and thus the binary severe VSL. No change made. (4) Proposed IRO-002-4: The SDT has adjusted the VSLs for Requirements R1 and R2 to gradate the terms to correspond to approved IRO-002-2. See summary consideration for revision.		
ISO/RTO Standards Review Committee (SRC) Independent Electricity System Operator	No	Please reference above comments regarding individual draft standards. In addition, we offer the following comments: a. IRO-008-2, R6: The LOWER VSL which makes reference to "Emergency" should be changed to "anticipated or actual SOL/IROL exceedance". Please see our comment under Q3, above, for details. b. IRO-010-2, R1: The SEVERE VSL for R1 can be reworded to "The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." Since there are only 4 parts in R1 and hence the "four or more" is inappropriate. c. IRO-017-1, R1: We do not believe the VSL for R1 should not be binary. R1 requires the RC to identify the roles and develop a process for coordinating outage plans, the latter to include several elements. It may well be a case where the RC did develop the process but missed some of the elements listed in Parts 1.1 to 1.4. For example, a LOWER VSL may be assigned if the RC did develop identify the roles and develop the process document, but missed one of the parts in 1.1 to 1.4. A MEDIUM VSL may be

Organization	Yes or No	Question 14 Comment
		assigned if the RC missed two of the parts, etc. We suggest the SDT to review the VSL development guideline and FERC's guideline, and revise the VSL for R1 accordingly. d. TOP-001-3, several requirements: Since we disagree with a number of requirements in this standard, we are unable to support the VSLs associated with these requirements. e. TOP-003-3, R5: This requirement contains 3 parts each of which specifies a particular aspect of data provision. It is conceivable that a responsible entity provided data as specified in R3 and R4 but failed to follow one or more of the specific format, process or protocol as depicted in Parts 5.1 to 5.3. Hence, having a binary VSL for R5 would imply that failing to meet just one of Parts 5.1 to 53 will render the responsible entity being assessed a SEVERE violation. This is inconsistent with the VSL guideline. We suggest the SDT to expand the VSL for R5 to cover the cases of failing to meet one and two of the three parts in R5. (Extracted from Q6) IRO-017-1: R2 VRFs should be Medium, not Low. (note: CAISO does not agree with this comment).
Response: a. Proposed IRO-008-2, Requirement R6: The term 'Emergency' is not included in the Lower VSL. No change made. a. Proposed IRO-010-2, Requirement R1: The SDT agrees and has made the suggested change. See summary consideration for revision. b. Proposed IRO-017-1, Requirement R1: The SDT agrees and has made the suggested change. See summary consideration for revision. c. Proposed TOP-001-3: Without specific comments on the VSLs, the SDT is unable to respond. d. Proposed TOP-003-3, Requirement R5: The SDT agrees and has made the suggested changes. See summary consideration for revision. e. Proposed IRO-017-1, Requirement R2: The SDT agrees and has made the suggested change. See summary consideration for revision.		
Georgia System Operations	No	The bandwidth between "lower" and "severe" VSL is only 15 minutes. Expand bandwidth.

Organization	Yes or No	Question 14 Comment
Georgia Transmission Corporation		
Response: The SDT assumes this is referring to proposed TOP-001-3, Requirement R13 and/or proposed IRO-008-2, Requirement R5. The SDT has changed both sets of VSLs based on previous comments. See summary consideration for revision.		
Rutherford EMC	No	See comments on TOP-003. (Extracted from Q9) TOP-003-3: In the Table of Compliance Elements, the severity and risk for R5 is medium with only a Severe VSL. All other requirements in this standard are low and have graduated levels of severity. In IRO-10, the same failure has graduated levels of severity. This is inconsistent and should be rectified.
Response: The SDT agrees and has made the items consistent as suggested. See summary consideration for revision.		
Austin Energy	No	City of Austin dba Austin Energy (AE) provides the following comments regarding VSLs: (1) The VSL for TOP-003-3, R5 should parallel the VSL for IRO-010-2, R3. (2) The VSL for IRO-010-2, R2 should have the note regarding starting at the Severe VSL similar to TOP-003-3, R3 and R4 and others. (3) The VSLs for TOP-001-3, R3 and R5 should parallel the VSL for IRO-001-4, R2. (4) The VSLs for TOP-001-3, R4 and R6 should parallel the VSL for IRO-001-4, R3.
Response: (1) The SDT agrees and has made the suggested changes. See summary consideration for revision. (2) The SDT agrees and has added the note as suggested. See summary consideration for revision. (3) While the language is not identical, the content and intent of the proposed TOP-001-3, Requirements R3 and R5 VSL do parallel the content and intent of proposed IRO-001-4, Requirement R2 VSL. No change made. (4) While the language is not identical, the content and intent of the VSLs for proposed TOP-001-3, Requirements R4 and R6 do parallel the VSL for proposed IRO-001-4, Requirement R3. No change made.		

Organization	Yes or No	Question 14 Comment
Electric Reliability Council of Texas, Inc.	No	Please reference above comments regarding individual draft standards.
Response: Please see responses to previous comments.		
Sacramento Municipal Utility District/Balancing Authority Northern California	No	No, the IRO-002-4 VSL provide no alternative other than Severe. In cases where one element of several hundreds could be missed this effectively creates a zero tolerance.
Response: No requirements are specified here so the SDT is unable to provide a detailed response. However, the SDT did change the VSLs for both Requirements R1 and R2 of proposed IRO-002-4 based on other comments and believes this may address the commenter's concerns. See summary consideration for revision.		
PJM Interconnection	Yes	(Extracted from Q12) IRO-008-2, R5: Additionally, the VRF and VSLs for R5 will require revision to address the two hour timeframe allowed for in EOP-008.
Response: The SDT has made changes to IRO-008-2, Requirement R5 data retention and VSLs based on comments received that should address your concerns. See summary consideration for revision.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
PPL NERC Registered Affiliates	Yes	
Peak Reliability	Yes	

Organization	Yes or No	Question 14 Comment
Rayburn Country Electric Cooperative	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Xcel Energy	Yes	
PNMR	Yes	
Consumers Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Salt River Project	Yes	
Response: Thank you for your response.		

15. Are there any other concerns with these standards that haven't been covered in previous questions and comments?

Summary Consideration: The SDT has provided clarification to numerous comments and has made the following changes due to industry comments:

> **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.)
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> **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
>
> **Effective Date/Implementation Plan for proposed IRO-010-2 and TOP-003-3:** Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Organization	Yes or No	Question 15 Comment
PacifiCorp	Yes	Although PacifiCorp supports the elimination of duplicate language in these Standards, much of the new language in the revised Standards is diluted and is more vague as a result.
Response: Without specific comments, the SDT is unable to respond.		

Organization	Yes or No	Question 15 Comment
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc	Yes	1. Special Protection Systems should be addressed in their own requirements. 2. Phase Angle limitations should be greater than 300 kV. 3. The FRCC MS OC would like to thank the TOP/IRO SDT for their time and effort in developing the proposed changes to the NERC Reliability Standards as part of this important initiative. We support the SDT efforts conceptually, and have provided comments on improving the language and clarity of some of the proposed requirements. However we do have some questions and concerns that need to be addressed prior to giving the project our full support.
Response: 1. These standards only deal with data from Special Protection Systems or to make certain that the data is included in analysis and assessments. Technical details concerning Special Protection Systems remain in the PRC standards. No change made. 2. With no technical justification provided for the suggested change, the SDT is unable to provide a response. No change made. 3. Thank you for your support.		
Duke Energy	Yes	As stated in our comments above, Duke Energy has significant concerns regarding aspects of the proposed TOP/IRO standards. We believe they are in direct conflict with the current Functional Model roles and responsibilities upon which the industry has built processes, procedures, software, and infrastructure. The industry approved Functional Model defines the various relationship, functions, the tasks performed by these functions, the responsible time horizons and the relationships between the entities responsible for performing tasks associated with each function. It is this model that provides the foundation and the framework upon which NERC is to develop and maintain Reliability Standards. Furthermore, the idea that reliability begins with and centers completely around the RC is a mistake as it removes the defense-in-depth strategy currently in place. The RC should be the last line of defense, not the first. Reliability does not start with the RC; it begins with the TOPs and BAs and the standards should acknowledge and emphasize this important tenet of reliability. The RC's role is to maintain a wide-area

Organization	Yes or No	Question 15 Comment
		view and prevent system events - having them involved in every TOP's normal operations at all times distracts from the RC's responsibility and will have significant consequences. Duke Energy is not opposed to visiting the re-assignment of said responsibilities and applicable time horizons, however, we feel that this task should be done through an amendment of the Functional Model, and not through the Reliability Standards process.
Response: The SDT believes the proposed standards are consistent with the NERC Functional Model and responsive to concerns raised by FERC in the NOPR. Specific responses to Duke's comments on the functional model are provided in the appropriate sections.		
FirstEnergy	Yes	FirstEnergy recommends striking the words "or degradation" in the proposed definitions for both Operating Planning Analysis and Real Time Assessments.
Response: The SDT believes that degradation information is necessary for an appropriate level of situational awareness. No change made.		
SPP Standards Review Group	Yes	There are numerous instances in the Measures of all the proposed standards where the phrase 'but not limited to' is included. In some instances this phrase is set off by commas and in others it is not. When the commas are used, the second comma appears out of place. We suggest deleting the commas entirely as it is done in several of the Measures. Requirements R10 and R11 in TOP-001-3, Requirement 1, Part 1.2 in TOP-003-3, Requirement R4 in IRO-002-4, Requirement R1, Part 1.2 and the revised definitions for Operational Planning Analysis and Real-time Assessment include a reference to the term Special Protection Systems. There is a new proposal at NERC to replace this term with Remedial Action Scheme. If this change comes about, how will this change be reflected in this set of revised standards?
Response: The SDT agrees and has removed all commas.		

Organization	Yes or No	Question 15 Comment
The SDT must use the terms as they presently exist in the approved Glossary of Terms. Another team is working on the Special Protection System/Remedial Action Scheme issue. If they decide to make that change, part of their responsibility will be to bring all standards up to date with this change.		
ACES Standards Collaborators Georgia Transmission Corporation	Yes	(1) We recommend that the drafting team post redlines with each standard, so it is easier to view the proposed changes. Having clean copies of the revisions only adds more time to have to track changes and it is a very inefficient use of industry's time. (2) The drafting team should consider reducing the amount of information in the posting, or extending the comment period to allow for a thorough review by industry. We recommend holding a technical conference or a series of webinars (instead of just one) to go through each of the standards in detail. The amount of information cannot be covered in a single hour-long webinar. (3) Why did the SDT not review PRC-001? The words "coordinate" and "familiar" are ambiguous words that have caused issues with compliance and enforcement for years. It is disappointing that this issue has not been addressed. (4) Thank you for the opportunity to comment.
Response: (1) It is not practical to review redlined versions of the standards for this project due to the extensive revisions from the currently enforceable standards. The mapping document is a more efficient mechanism for tracking changes. (2) The SDT will provide additional opportunities to discuss details of the proposed standards with stakeholders in the future. Because the standards must be filed with FERC by January 15, it is not possible to provide longer comment periods. The tremendous effort put forth by the industry to review the standards and provide thoughtful feedback has kept the project on track and is deeply appreciated by the SDT. (3) PRC-001 is not in scope for this project.		
Peak Reliability	Yes	Operational Planning Analysis proposed definition should address the modeling of impacts of sub-100 kV and SPS/RAS - not just the status of SPS/RAS.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 15 Comment</th></tr>
<tr><td></td><td></td><td>Also “The evaluation shall reflect inputs” should be “The evaluation reflects inputs” to avoid the appearance of having a Requirement within a definition.</td></tr>
<tr><td colspan="3">Response: As written in the proposed definition, an Operational Planning Analysis is an evaluation of projected system conditions to assess anticipated and potential conditions for next day operations. Certain inputs, like Protection System and Special Protection System status, are specified to ensure that the Operational Planning Analysis contains sufficient detail to provide appropriate situational awareness. The proposed definition describes what an Operational Planning Analysis is, and the SDT believes that a description of how an Operational Planning Analysis is conducted as suggested by the commenter is not necessary.

To address this and other feedback from industry, the SDT has added “applicable” to the definition of Real-time Assessment and Operational Planning Analysis to further clarify the definitions. See summary consideration for revision.</td></tr>
<tr><td>CenterPoint Energy Houston Electric LLC.</td><td>Yes</td><td>CenterPoint Energy is concerned with the existing NERC defined term Transmission Operator Area being introduced in the TOP Standards as it is currently written. Transmission Operator Area: The collection of Transmission assets over which the Transmission Operator is responsible for operating. In the ERCOT region individual Local Control Centers operate Transmission assets under the direction of ERCOT ISO while both are jointly registered Transmission Operators under a Coordinated Functional Registration. CenterPoint Energy recommends a revised definition under Section D, Regional Variances to address this established joint responsibility. The revised definition would read as follows: Transmission Operator Area (ERCOT Region): The collection of Transmission assets over which the Transmission Operator is responsible for operating or directing operation.</td></tr>
<tr><td colspan="3">Response: The SDT believes that a variance is not required as it is widely understood that acting could include directing others to act. And the responsibility for actions doesn’t change regardless of whether the Transmission Operator performs the actual actions itself or directs others to do the actions. No change made.</td></tr>
<tr><td>City of Garland</td><td>Yes</td><td>Implementation Plan Concern In the Implementation Plan, IRO-010-2 and TOP-003-3 both have requirements that are intended to go into effect on different dates to allow data specifications to be developed / distributed to entities and those receiving entities have time to gather / format data and send back to the requesting entities.</td></tr>
</table>

Organization	Yes or No	Question 15 Comment
		Both effective dates refer to the 1st day of the 1st calendar quarter that occurs either 10 months or 12 months after the approval date (FERC's approval in the US). Because of the 2 months separation, there is one month in each quarter that if FERC approves the standards in that month, the 10 months & 12 months later will both fall in the same quarter resulting both effective dates starting on the same 1st day of the 1st quarter following. Recommendation: Change language to where the two sets of requirements will go into effect one quarter apart. Definitions Concern is with the portion of the definition of "Operational Planning Analysis" and "Real Time Assessments" that lists "identified phase angle". It is not clear what "identified" means. "Identified" should mean that the Entity will identify representative points across the area for which it is responsible - not every available point in the system (larger geographic areas would probably need more points than small geographic areas). Also, PMUs require a large bandwidth to pass the tremendous amount of data collected thus making the communication costs prohibitive for small entities.
Response: The SDT agrees and has changed the Implementation Plan to a 9 month/12 month increment as well as the Effective Dates for proposed IRO-010-2 and TOP-003-3. See summary consideration for revisions. The part of the definition that is referenced here is actually **"…** *and identified phase angle and equipment limitations…"* This means that any identified limitations in dealing with phase angles should be incorporated into the analysis. The SDT has added the term 'applicable' to the definition list for clarification. No change made. If an entity does not have PMU data then this is not an issue. If an entity has PMU data, then the SDT believes that the entity will have built its systems to be able to handle the volume of data associated with the PMU data. The Reliability Coordinator is not going to request data just for the sake of having it and will only request data that it truly needs. This could assist in dealing with the volume of data going across the link. In addition, the requirement cites mutual agreeability which assures that the controlling entity can't request something that the submitting entity simply can't provide. No changes made.		
American Electric Power	Yes	AEP's negative vote on TOP-002-4 is solely driven by the proposed definition on which it relies, not on the direction or intent of the standard itself. Comments

Organization	Yes or No	Question 15 Comment
		regarding proposed definitions: Operating Planning Analysis: ”Identified phase angle...limitations” needs to be clarified. The definition could be interpreted as requiring either a) continual analysis of all phase angles or b) analysis of pre-determined phase angle limitations at specific locations. AEP believes the definition should specifically state that it applies only to analysis of pre-determined phase angle limitations at specific locations. In the event continual analysis is required, what determines the placement and number of measurements for a given system? In that case, the definition should clarify that if phase angle is considered in the study, and if a phase angle limitation is identified, than that limitation should be included in the analysis. Rather, AEP proposes the following definition: “An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation should reflect inputs such as (but not limited to): load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)” Real-time Assessment: Once again, AEP has concerns similar those expressed for the definition of Operating Planning Analysis, as the definition for Real-time Assessment should specifically state that it applies only to analysis of pre-determined phase angle limitations at specific locations. We propose the following definition: “An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment should reflect inputs such as (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 contracted services.)”

Organization	Yes or No	Question 15 Comment
Response: The part of the definition that is referenced here is actually **"…** *and identified phase angle and equipment limitations…"* This means that any identified limitations in dealing with phase angles should be incorporated into the analysis. The SDT has added the term 'applicable' to the definition list for clarification. No change made.		
NIPSCO	Yes	NIPSCO has the following comments about the new Definitions: 1. In the new definition of Operational Planning Analysis and Real-time Assessment, Facility Rating and equipment limitations are listed. NIPSCO feels these should be removed and SOL and IROL be added. SOL and IROL include but is not limited to Facility Ratings and equipment limitations. 2. In the new definition of Operational Planning Analysis and Real-time Assessment, Phase Angle is listed as an included input. NIPSCO feels this needs more definition. Is this for every node?
Response: The SDT believes it is appropriate to consider Facility Rating and equipment limitations in the Operational Planning Analysis and Real-time Assessment and not limit the inputs to more narrowly defined SOLs and IROLs. No change made. Identified phase angle and equipment limitations are listed as an input in response to Southwest Outage Report recommendation number 27. The proposed definition works in concert with requirements in the proposed standards (e.g., proposed TOP-001-3 Requirement R14) to provide the necessary situational awareness for reliable operations. The proposed definition provides flexibility for the responsible Transmission Operator, Balancing Authority, or Reliability Coordinator to determine specific inputs. Those entities will only be asking for such data where they feel they need it and the data specification concept will allow entities to come to mutual agreement as to what phase angle data is required.		
PJM Interconnection	Yes	PJM recommends that the drafting team review the requirements in the TOP standards which are applicable to the BA and in which the GO is performing a specific requirement. PJM suggests these requirements be reviewed and moved to the appropriate BAL standards, if they are determined to still be necessary.
Response: The SDT generally supports the concept of having the TOP standards for the Transmission Operator, the IRO standards for the Reliability Coordinator and the BAL standards for the Balancing Authority; however, BAL standards are not in the scope of this		

Organization	Yes or No	Question 15 Comment
project. Therefore, the SDT believes the requirements and applicable entities are currently organized appropriately to support the purpose of each proposed standard and in response to the defined scope of this project. No change made.		
Austin Energy	Yes	City of Austin dba Austin Energy (AE) provides the following comments on the definitions of Operational Planning Analysis and Real-time Assessment: (1) Consider changing the use of the term "Special Protection System" to "Remedial Action Scheme" to match Project 2010-05.2. (2) Please clarify what is meant by incorporating "identified phase angle and equipment limitations." Does the SDT intend this to cover limitations in real and reactive capability? (3) Additionally, AE provides this third comment on the definition of Transmission Operator Area, which is rarely used in existing standards but is included in the TOP/IRO family revisions. In the ERCOT Region, both ERCOT ISO and each local control center are each registered as TOPs. A CFR matrix delineates the responsibility for each requirement applicable to the TOP function. The general concept in the ERCOT Region is that individual local control centers operate Transmission assets under the direction of ERCOT ISO. Logically, one would assume that each Transmission Operator would have a Transmission Operator Area. However, the current definition poses a potential conflict. As defined in the NERC Glossary, a Transmission Operator Area is "The collection of Transmission assets over which the Transmission Operator is responsible for operating." ERCOT does not operate Transmission assets, rather, it directs the operation of Transmission assets. Therefore, AE suggests a revision and regional variance to the definition as follows: "Transmission Operator Area (ERCOT Region): The collection of Transmission assets over which the Transmission Operator is responsible for operating or directing operation."
Response: The SDT must use the terms as they presently exist in the approved Glossary of Terms. Project 2010-05.2 is working on the Special Protection System/Remedial Action Scheme issue. If they decide to make that change, part of their responsibility will be to bring all standards up to date with this change.		

Organization	Yes or No	Question 15 Comment
The part of the definition that is referenced here is actually **"…** *and identified phase angle and equipment limitations…"* This means that any identified limitations in dealing with phase angles should be incorporated into the analysis. No constraints exist as to Real or Reactive Power. The SDT has added the term 'applicable' to the definition list for clarification. No change made. The SDT believes that a variance is not required as it is widely understood that acting could include directing others to act. And the responsibility for actions doesn't change regardless of whether the Transmission Operator performs the actual actions itself or directs others to do the actions. No change made.		
Oncor Electric Delivery LLC	Yes	Oncor does not support the two proposed definitions in proposed in Project 2014-03 Revisions to TOP/IRO Reliability Standards; Operational Planning Analysis and Real-time Assessment. The definitions state the minimum inputs that must be included in the evaluation of each Operational Planning Analysis and Real-time Assessment for pre and post contingency conditions. Some of the inputs listed that shall be included are not feasible for post contingency analysis, such as phase angles. For Oncor to approve the definitions, recommend changing the wording from "shall reflect inputs including" to "may reflect inputs including" in both definitions. Operational Planning Analysis Oncor's proposed recommendation: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) Real-time Assessment Proposed definition: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect 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 contracted services.)"

Organization	Yes or No	Question 15 Comment
		Furthermore, Oncor has concern that the proposed Standards place unnecessary requirements on Transmission Operators (TOPs) to run Operational Planning Analysis and Real-time Assessments. As stated in response to Question 7 (TOP-001-3) and Question 12, the 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. Requiring Transmission Operators to replicate Real-time Assessments and Operational Planning Analysis currently performed by the Reliability Coordinator (ERCOT) creates added expense and contributes no added reliability to the BES. Oncor requests the SDT consider placing these functions (Operational Planning Analysis and Real-time Assessment) on the Reliability Coordinators only.
Response: To address this and other feedback from industry, the SDT has added "applicable" to the definition of Real-time Assessment and Operational Planning Analysis to further clarify the definitions. See summary consideration for revision.		
Texas Reliability Entity	Yes	1) Operational Planning Analysis definition: Recommend returning the phrase "may be performed either a day ahead or as much as 12 months ahead" to the proposed definition of Operational Planning Analysis. That language includes the full Operations Planning horizon, not just next day. The current effective definition contains that phrase. Development of an Operating Plan to address the exceedances of SOLs/IROLs may take longer than one day to develop, so it is necessary to have a requirement to perform an Operational Planning Analysis for the full Operations planning horizon. The proposed definition, in conjunction with TOP-002-4 R1 which directs TOPs to have an Operational Planning Analysis for the next day to assess whether there will be a SOL exceedance, doesn't account for the time frame from after one day up to 12 months. 2) There is a discrepancy between the definition of "operations planning horizon" in the Project 2014-03 SOL Exceedance White Paper and IRO-017-1. The white paper defines operations planning time horizon as "operating and resource plans from day-

Organization	Yes or No	Question 15 Comment
		ahead up to and including seasonal." IRO-017-1 (Note on part 1.5) defines the operations planning horizon as "next-day to one year out."
Response: 1) The SDT believes the suggested phrase is unnecessary. Neither the proposed definition nor the requirements specifically state when the Operational Planning Analysis is created, so an entity could prepare it at any time provided it reflects accurate inputs for next-day operations. 2) The correct usage is next-day to one year out. The SOL Exceedance White Paper has been updated to reflect this change.		
Salt River Project	Yes	TOP-003-3 R5 does not adequately cover the planning aspects of TOP-002-2.1b R15. TOP-003-3R5 seems to be a "follow direction" requirement where TOP-002-2.1b is a planning requirement.
Response: The proposed requirements in proposed TOP-003-3 work collectively to provide for the data needs of the Transmission Operator and Balancing Authority to fulfill their operational and planning responsibilities. The data specification allows for the Transmission Operator/Balancing Authority to ask for any data they need which could include the forecast of real power output previously cited in approved TOP-002-2.1b Requirement R15. No change made.		
Rayburn Country Electric Cooperative	No	: I would reinforce my support for reduction of standards by consolidation of requirements that use nearly identical if not identical language by creating role based groups of functional entities. I believe it makes a requirement clearer to understand since it is found only once within the NERC standards not in 2 or 3 different standards. It makes training easier as well, allowing the focus to be on the required action.
Response: The SDT purposely kept these standards separate to keep the focus on the functional entities responsible: Reliability Coordinators for proposed IRO standards and Transmission Operators and Balancing Authorities for proposed TOP standards. This was part of the scope for the originating projects (Project 2006-06 and Project 2007-03). No change made.		
Northeast Power Coordinating Council	No	

Organization	Yes or No	Question 15 Comment
Arizona Public Service Company	No	
Associated Electric Cooperative, Inc. - JRO00088	No	
Colorado Springs Utilities	No	
SERC OC Review Group	No	
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	No	
PPL NERC Registered Affiliates	No	
ISO/RTO Standards Review Committee (SRC)	No	
Bonneville Power Administration	No	

Organization	Yes or No	Question 15 Comment
Georgia System Operations	No	
EDP Renewables North America LLC	No	
Volkmann Consulting	No	
Manitoba Hydro	No	
Exelon Ccompanies	No	
Ingleside Cogeneration LP	No	
Xcel Energy	No	
American Transmission Company	No	
Idaho Power	No	
PNMR	No	
David Kiguel	No	
Consumers Energy	No	
Liberty Electric Power, LLC	No	
Hydro One	No	

Organization	Yes or No	Question 15 Comment
Tri-State Generation and Transmission Association, Inc.	No	
Hydro One	No	I sent in comments earlier but I have updated them now to include comments about IRO-017-1.
INDN - Independence Power & Light	No	
MidAmerican Energy	No	
Electric Reliability Council of Texas, Inc.	Yes	ERCOT believes that significant progress has been made to address the FERC orders, expert recommendations, and remove redundancies while maintaining reliability-based requirements. Outside of the issues raised in our comments and the IRC SRC comment, ERCOT supports the remainder of the proposed changes.
Response: Thank you for your response.		

END OF REPORT