Consideration of Comments

Real-time Transmission Operations Project 2007-03

The Real-time Transmission Operations Drafting Team thanks all commenters who submitted comments on the 6th draft of the standards for Real-Time Operations (Project 2007-03). These standards were posted for a 30-day public comment period from December 14, 2011 through January 12, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 59 sets of comments, including comments from approximately 178 different people from approximately 103 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The SDT changed the following items due to industry comments received:

- TOP-001-2:
  - Requirement R1 – Allowed for plural Transmission Operators and deleted first instance of 'identified'
  - Requirement R6 – changed 'the' to 'its' Reliability Coordinator
  - Requirement R8 – changed 'internal area ' to 'internal to its Transmission Operator Area'; changed the Time Horizon to only Operations Planning
  - Requirement R10 – changed 'each' SOL to 'an' SOL
  - Data Retention – Changed voice recordings to 90 calendar days from three calendar months
- TOP-002-3:
  - Requirement R3 – changed 'internal area ' to 'internal to its Transmission Operator Area'
- TOP-003-2:
  - Applicability – added Distribution Provider
  - Requirement R2 – added analysis functions for the Balancing Authority
  - Requirement R3 – Cited the tie to Requirement R1 and made the language in Requirement R3 consistent with that in Requirement R1
  - Requirement R4 - Cited the tie to Requirement R2 and made the language in Requirement R4 consistent with that in Requirement R2
  - Requirement R5 – added Distribution Provider
  - Measures M3 and M4 – clarified the web posting item of evidence

In addition, the SDT changed VSLs for TOP-001-2, Requirements R1, R3, R5, R8, and R10, plus VSLs for TOP-002-3, Requirement R3, and TOP-003-2, Requirements R1, R2, R3, and R4.

After the Quality Review was completed, the SDT made the following changes:

- TOP-001-2:
  - Requirement R1 – eliminated the plural context
  - Requirement R3 – clarified the plurality context
  - Requirement R5 – clarified the list of items
  - Measures – added attestations as evidence when no event has occurred
  - Compliance section – updated to latest revision
  - VRF justifications – moved away from using proposed requirements where possible
  - Requirement R1 VSL – clarified language
  - Requirements R3, R5, and R6 VSLs – added percentages
  - Requirement R8 – added language to exactly match requirement
  - Issues resolution – clarified language
  - Implementation Plan – clarified language
- TOP-003-2:
  - Requirements R1 and R2 – deleted use of 'required'
  - Measures M3 and M4 – corrected typo
  - Compliance section – updated to latest revision
  - VRF justification - moved away from using proposed requirements where possible

Minority comments included:

- Use of Reliability Directive – Some commenters object to the use of an unapproved definition, Reliability Directive, in TOP-001-2. They feel that it presents coordination problems and could cause a change to the standard if the definition is changed during its balloting. The SDT explained that it was working closely with Project 2006-06 which is developing the definition. Indeed, there are several members of the RTOSDT who are also on the RCSDT. The SDT also assures commenters that the need to coordinate filing the two projects, 2006-06 and 2007-03, has been forwarded to NERC management.
- There was concern about possible double jeopardy with TOP-003-2, Requirements R1/R3 and R2/R4. The SDT explained that double jeopardy should not be a concern as the two requirements represent two different actions: one to create the specification and one to distribute it. The two separate and distinct actions mean that there are two distinct reliability outcomes and that two separate requirements are needed.

TOP-001-2 did not pass initial ballot. The SDT made several changes to this standard to respond to comments and negative ballots. The SDT is recommending that TOP-001-2 be approved for a successive ballot.

TOP-002-3 passed its initial ballot but the SDT made a change to the effective date in response to comments. Therefore, the SDT is recommending that TOP-002-3 be advanced to a successive ballot.

TOP-003-2 did not pass initial ballot. The SDT made several changes to this standard to respond to comments and negative ballots. The SDT is recommending that TOP-003-2 be approved for a successive ballot.

All comments submitted may be reviewed in their original format on the standard's project page:

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Brian Evans-Mongeon	Utility Services	NPCC	8
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Chantel Haswell	FPL Group, Inc.	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1

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

11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Emily Pennel	Southwest Power Pool Regional Entity										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Robert Rhodes	Southwest Power Pool	SPP	2
3.	Ashley Stringer	OMPA		4
4.	John Allen	City utilities of Springfield	SPP	1, 4
5.	Michelle Corley	CLECO	SPP	1, 3, 5
6.	Ron Gunderson	NPPD	MRO	1, 3, 5
7.	Terri Pyle	OGE	SPP	1, 3, 5
8.	Valerie Pinamonti	AEP	SPP	1, 3, 5
9.	Tiffani Lake	Westar	SPP	1, 3, 5, 6
10.	Jim Useldinger	KCPL	SPP	1, 3, 5, 6
11.	Mahmood Safi	OPPD	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Joe O'Brien	NIPSCO	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe O'Brien	NIPSCO	RFC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Annie Lauterbach	Bonneville Power Administration	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.	Timothy Loepker	Dittmer Dispatch	WECC	1
2.	John Anasis	Technical Operations	WECC	1
3.	Theodore Snodgrass	Monroe Dispatch	WECC	1

				1	2	3	4	5	6	7	8	9	10
5.	Group	Albert DiCaprio	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Thompson	AESO	WECC	2
2.	Gary DeShazo	CAISO	WECC	2
3.	Steven Myers	ERCOT	ERCOT	2
4.	Ben Li	IESO	NPCC	2
5.	Matt Goldberg	ISO-NE	NPCC	2
6.	Bill Phillips	MISO	RFC	2
7.	Donald Weaver	NBSO	NPCC	2
8.	Greg Campoli	NYISO	NPCC	2
9.	Patrick Brown	PJM	RFC	2
10.	Charles Yeung	SPP	SPP	2

				1	2	3	4	5	6	7	8	9	10
6.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Reed	FE	RFC	
2.	Kevin Querry	FE	RFC	
3.	Bill Duge	FE	RFC	
4.	Brian Orians	FE	RFC	
5.	Gary Pleiss	FE	RFC	
6.	Sherri Rhodes	FE	RFC	

				1	2	3	4	5	6	7	8	9	10
7.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Juel Fugett	IID	WECC	1, 3, 4, 5, 6
2.	Alfonso Juarez	IID	WECC	1, 3, 4, 5, 6

				1	2	3	4	5	6	7	8	9	10
8.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team		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.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Robert Rhodes	Southwest Power Pool	SPP	2
3.	Ashley Stringer	OMPA		4
4.	John Allen	City utilities of Springfield	SPP	1, 4
5.	Michelle Corley	CLECO	SPP	1, 3, 5
6.	Ron Gunderson	NPPD	MRO	1, 3, 5
7.	Terri Pyle	OGE	SPP	1, 3, 5
8.	Valerie Pinamonti	AEP	SPP	1, 3, 5
9.	Tiffani Lake	Westar	SPP	1, 3, 5, 6
10.	Jim Useldinger	KCPL	SPP	1, 3, 5, 6
11.	Mahmood Safi	OPPD	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
9.	Group	Connie Lowe	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Mike Garton		NPCC	5
2. Michael Gildea		MRO	5
3. Louis Slade		RFC	5, 6
4. Michael Crowley		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
10.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Harold Wyble	Kansas City Power & Light	SPP	1, 3, 5, 6
2. Jim Useldinger	Kansas City Power & Light	SPP	1, 3, 5, 6
3. Jessi Tucker	Kansas City Power & Light	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
11.	Group	Gerald Beckerele	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Vicky Budreau	Santee Cooper	SERC	1, 3, 5, 9
2.	Cindy Martin	Southern	SERC	1, 3, 5
3.	Bob Dalrymple	TVA	SERC	1, 3, 5, 9
4.	Merritt Castello	Southern	SERC	1, 3, 5
5.	Scott Brame	NCEMC	SERC	3, 4
6.	Tim Lyons	OMU	SERC	1, 3, 5
7.	Jake Miller	Dynegy	SERC	5

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

8.	Marc Butts	Southern	SERC	1, 3, 5
9.	Mike Hirst	Cogentrix	SERC	5, 6
10.	Joel Wise	TVA	SERC	1, 3, 5, 9
11.	Andy Burch	EEI	SERC	1, 5
12.	Byron Thomasson	PowerSouth	SERC	1, 3, 5, 9
13.	Tim Hattaway	PowerSouth	SERC	1, 3, 5, 9
14.	Travis Sykes	TVA	SERC	1, 3, 5, 9
15.	Randy Hubbert	Southern	SERC	1, 3, 5
16.	Dwayne Roberts	OMU	SERC	1, 3, 5
17.	Hugh Francis	Southern	SERC	1, 3, 5, 9
18.	Larry Akens	TVA	SERC	1, 3, 5, 9
19.	Mike Hardy	Southern	SERC	1, 3, 5
20.	Greg Rowland	Duke	SERC	1, 3, 6
21.	Sam Holeman	Duke	SERC	1, 3, 6
22.	Melinda Montgomery	Entergy	SERC	1, 3
23.	Brad Young	LGE/KU	SERC	1, 3, 6
24.	Carter Edge	SERC	SERC	10
25.	Steve McElhaney	SMEPA	SERC	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Will Smith	MRO-NSRF	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Tom Webb	WPS	MRO	3, 4, 5, 6
4.	Jodi Jenson	WAPA	MRO	1, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Alice Ireland	Xcel/NSP	MRO	1, 3, 5, 6
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
9.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
10.	Scott Nickels	RPU	MRO	4
11.	Terry Harbour	MEC	MRO	3, 5, 6, 1
12.	Marie Knox	MISO	MRO	2

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

13.	Lee Kittelson	OTP	MRO	1, 3, 4, 5
14.	Scott Bos	MPW	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
13.	Group	Brenda Powell	Constellation Energy						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	C. J. Ingersol	Constellation Energy Control & Dispatch	SERC	3
2.	Amir Hammad	Constellation Power Source Generation, Inc.		5

				1	2	3	4	5	6	7	8	9	10
14.	Group	Jason Marshall	ACES Power Marketing Member Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Watson	Old Dominion Electric Cooperative	SERC	3, 4, 5, 6
2.	Mohan Sachdeva	Buckeye Power	RFC	4, 5, 6
3.	Bob Solomon	Hoosier Energy	RFC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
15.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
16.	Individual	Eric Ruskamp	Lincoln Electric System (LES)	X		X		X	X				
17.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
18.	Individual	Brent Ingebrigtson	LG&E and KU Serivces	X		X		X	X				
19.	Individual	Neil Phinney	Georgia System Operations			X	X						
20.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
21.	Individual	Shaun Anders	City Water Light and Power (CWLP) - Springfeild - IL	X		X		X					
22.	Individual	Jonathan Appelbaum	United Illuminating Company	X									
23.	Individual	Jonathan Appelbaum	United Illuminating	X									
24.	Individual	Rich Vine	California Independent System Operator		X								
25.	Individual	Thomas E Washburn	FMPP						X				
26.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
27.	Individual	Howard Rulf	We Energies			X	X	X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
29.	Individual	Jeff Longshore	Luminant Energy Company, LLC						X				

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
30.	Individual	DAVID DOCKERY	Associated Electric Cooperative, Inc.	X		X		X	X				
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	Robert Roddy	Dairyland Power Cooperative	X		X		X					
33.	Individual	Kathleen Goodman	ISO New England Inc.		X								
34.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
35.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP - Occidental Chemical Corporation					X					
36.	Individual	David Thorne	Pepco Holdings Inc	X		X							
37.	Individual	Mahmood Safi	Omaha Publc Power District	X		X		X	X				
38.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
39.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
40.	Individual	Dana Showalter	E.ON Climate & Renewables					X					
41.	Individual	Don Jones	Texas Reliability Entity										X
42.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
43.	Individual	Rich Salgo	NV Energy	X		X		X	X				
44.	Individual	Gregory Campoli	New York Independent System Operator		X								
45.	Individual	Martin Bauer	US Bureau of Reclamation					X					
46.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
47.	Individual	Anthony Jablonski	ReliabilityFirst										X
48.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
49.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
50.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
51.	Individual	Edvina Uzunovic	The Valley Group, a Nexans Company										
52.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
53.	Individual	Terri Pyle	Oklahoma Gas and Electric	X		X		X					
54.	Individual	Julie Lux	Westar Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
55.	Individual	Thad Ness	American Electric Power	X		X		X	X				
56.	Individual	Brenda Truhe	PPL Electric Utilities	X									
57.	Individual	Bill Keagle	BGE	X									
58.	Individual	Kirit S. Shah	Ameren	X		X		X	X				
59.	Individual	Jason Snodgrass	GTC	X									

1. **The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Comments were made on all Requirements within TOP-001-2. Most of these comments indicated individually preferred language that the SDT did not feel improved clarity, and were therefore not adopted.

In response to a large group of comments, Requirement R8 was modified to replace the phrase "its internal area reliability" with "reliability internal to its Transmission Operator Area".

The SDT clarified in its response that the term 'continuous duration' has its common meaning.

In response to comments, minor changes were made to Requirements R1, R6, and R10 to improve clarity.

The Time Horizon for Requirement R8 was changed to Operations Planning only.

Conforming changes were made to the respective Measures, VSLs, and VRFs.

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless -such actions would violate safety, equipment, regulatory, or statutory requirements.

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

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or ~~each~~an SOL identified in Requirement R8, has been exceeded.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
California ISO	Negative	R6 requires Balancing Authorities and Transmission Operators to notify “negatively impacted interconnected NERC registered entities” of planned outages. This term is not specific enough to narrow down who must be notified. For instance, with this open-ended wording it could be construed that BAs would have to notify LSEs and DPs in their areas which would be an onerous task. We would recommend staying with “negatively-affected BAs and TOPs.” The wording in R9 is confusing and is not specific enough to ensure compliance. In particular the requirement prohibits operation outside any SOL “for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.” However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. In addition, under R9 and M9, how will the word “continuous” be defined or measured? This is extremely important to understand because the VSL table states the following as Severe for R9: “The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria.” It seems that the effective date should be set much sooner than 24 months following approval since there are basically no new requirements associated with this standard. Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Response: Regarding Requirement R6, since telemetry has definite parties at each end, the Balancing Authority or Transmission Operator with the telemetry issue is in the best position to know which other parties are affected by its telemetry outages. No change made. Regarding Requirement R9, ratings include the element of time. In view of the current NERC definitions of IROLs and SOLs, the language is correct as is written. The definition of IROLs describes the negative results that could occur when an IROL is exceeded		

Organization	Yes or No	Question 1 Comment
for a time greater than its T_v. The definition for SOL does not have this language, so no "... instability, uncontrolled separation(s) or cascading outages...." happens upon the exceedance of an SOL that is not an IROL. No change made. In Requirement R9 and Measure M9, 'continuous duration' has its common meaning. No change made. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months for all requirements except the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Colorado Springs Utilities	Negative	Colorado Springs Utilities (CSU) appreciates the work of the SDT to reconcile the various requirements into TOP-001, -002, & -003; and this opportunity to comment. The language of this group of standards has improved much with each draft. However, CSU continues to be concerned with the creation of an apparently "special" class of SOL in TOP-001-3 R8, R9 & R11 - creating what seems to be a middle category between "run of the mill" SOLs and IROLs; with no guidance, whatsoever, on how SOLs should qualify for or be excluded from this intermediate treatment. FAC-011 & FAC-014 already adequately cover identification and communication of SOLs and IROLs, and CSU believes that, if any additional SOL categories need be created, they should be more appropriately addressed in those standards. Additionally, there is no definition and a lack clarity for the concept of "supporting internal area reliability". In previous Considerations, the SDT has stated, "Requirements R8 and R10 were added due to comments from a significant portion of the industry during the extensive posting process of these standards." But, as the SDT has acknowledged, "There is still some debate as to what is meant by internal area reliability." The SDT continued, "The SDT continues to believe, as stated in previous responses, that the Transmission Operator is best suited to determine what affects its internal area and the resolution of those issues are best left to the Transmission Operator." If best left to the Transmission Operator, then one wonders why this "special" SOL should be added to the Standard? This concept is obviously causing much consternation amongst responding entities and has

Organization	Yes or No	Question 1 Comment
		the makings of, at best, a moot requirement (if no-one identifies any special SOLs) or, at worst, a compliance minefield - considering the questions that will come to an auditor’s mind when trying to assess compliance with these requirements as written. CSU also continues to feel strongly, despite protestations of the SDT to the contrary, that R7/R9 and R11 create a double jeopardy waiting to happen, and would best be appropriately combined.
Response: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. These requirements embed that concept in the standard. No change made. The SDT has replaced 'internal area reliability' with 'reliability within its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. These requirements are the core Transmission Operator requirements that assure continued reliable operation of the BES. If the Transmission Operator acts or directs others to act to mitigate, as in Requirement R11, but is unable to return the facility within its IROL with a time T_v or its SOL within its time criteria, then the Transmission Operator is compliant with Requirement R11 and noncompliant with either Requirement R7 or Requirement R9, as dictated by the exact circumstances. If the Transmission Operator fails to act or fails to direct others to act, as in Requirement R11, then it is noncompliant with both Requirement R11 and either Requirement R7 or Requirement R9, as dictated by the exact circumstances. This is not double jeopardy. No change made.		
MidAmerican Energy Co.	Negative	MidAmerican has concerns about TOP-001 R8 and R9. It appears the drafting team has unintentionally created an undefined subset or class of SOLs that are roughly equivalent to IROLs. More clarification is needed to clearly state that the new class of SOLs is a subset of all SOLs and not all

Organization	Yes or No	Question 1 Comment
		SOLs. MidAmerican recommends that R8 be modified to strike “each SOL” and replaced with “subset of Reliability Coordinator defined SOLs”. Otherwise auditors could argue that the NERC definition of a SOL includes all NERC BES devices since they all have thermal and voltage limits and therefore all NERC BES facilities apply to R8 and R9.
Response: The SDT believes that the language in Requirement R8 is clear. This requirement only applies to that subset of SOLs that are deemed to be more significant to the Transmission Operator than the typical SOL. This subset was intentionally created by the SDT in response to industry comments. The Transmission Operator must define its SOLs consistent with the Reliability Coordinator’s SOL methodology per FAC-014-2, Requirement R2. Thus, each SOL is defined per the Reliability Coordinator’s methodology. No change made.		
Muscatine Power & Water	Negative	Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the Standards Drafting Team requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9? Note that the SOL definition has a thermal rating component in it and we are not sure how you can’t draw SOLs into the same category as IROLs unless you clearly indicate these standards only apply to a subset.
Response: Typically, ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. For SOLs, the time limit varies according to the facility ratings used in the development of the SOL. No change made.		
Northeast Utilities	Negative	TOP-001-2 is referencing a NERC definition for “Reliability Directive” which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of “Reliability Directive” would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for “Reliability Directive” changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an “across the board”

Organization	Yes or No	Question 1 Comment
		usable definition.
Roger C. Zaklukiewicz	Negative	There currently is a definitionn for "Relibility Directive" which is listed in the Definition of Terms used in Standards. It is my understanding that the definition of the term "Relibility Directive" is being reviewed and probably will be rewritten/modified by the Relibility Coordinator Standards Drafting Team (Project 2006-06). Associated with this effort, is clarification of the term "Adverse Relibility Impact" which may have a significant impact on how TOP-001-2 is interpreted and administered throughout the industry. I believe the work of the Project 2006-06 Team should be coordinated with this initiative so that we have a greater level of certainty upon which we are casting a vote.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team as well.		
Oncor Electric Delivery	Negative	For R6- Oncor Electric Delivery respectfully submits this response as it does not believe that the proposed language will provide a coordinated communication effort in the event of a planned outages of telemetry, control equipment and associated communication channels. In addition, the term “negatively impacted interconnected registered entities” is too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity.
Response: The SDT is unsure of the intent of this comment, since no suggested alternative language was proposed. The SDT continues to believe that the Transmission Operator is in the best position to know which other parties are affected by its telemetry outages and it is not necessary to include the Reliability Coordinator into this item. Owner/operators of affected telemetry equipment have traditionally coordinated these outages. No change made.		

Organization	Yes or No	Question 1 Comment
Southwest Power Pool, Inc.	Negative	R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.

Response: The SDT made a conscious decision to raise the bar on IROLs to incorporate the T_v limit. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made.

Organization	Yes or No	Question 1 Comment
Requirement R9 does not apply to SOLs which are not identified in Requirement R8. No change made. The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. The SDT agrees. Conforming change made. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Tampa Electric Co.	Negative	Definitions for Reliabilty Directive should be with this ballot since it is the first to be balloted Is R4 to be interpreted that I must drop Firm load if the requesting TOP is droping Firm load. The words would imply that so I can't vote in the affirmative.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team also. No change made. Shedding firm load is one of the tools for maintaining the reliability of the BES. However, this does not mean that if the initiating Transmission Operator drops load, that the cooperating Transmission Operator must necessarily drop load. It is possible, however, that two or more Transmission Operators may need to shed load to resolve an operating issue. This requirement is intended to assure that the initiating Transmission Operator cannot demand that a cooperating Transmission Operator execute emergency actions that the initiating Transmission Operator has not been willing or able to implement. No change made.		
Northeast Power Coordinating	No	Requirements R1 and R2 should not be separate. Having them broken out

Organization	Yes or No	Question 1 Comment
Council		in this manner could potentially put entities in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then Requirement R4 should be broken down into two requirements. Requirement R4 states that information is being requested, AND is available. TOP-001-2 R2 states: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations] ☐ seems problematic and further work needs to be done on this requirement to ensure that the proper intent is codified. The intent we believe to be ..immediately upon recognition of the inability to perform a Reliability Directive within the stipulated or understood timeframe would result in informing the TO. The concern exists that an entity might be able to perform the directive but may not within the proper timeframe of the TOPs need. In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning Analysis as "An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much

Organization	Yes or No	Question 1 Comment
		as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency? The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency does not occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning.Suggest rewording Requirement R3 to:R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness

Organization	Yes or No	Question 1 Comment
		there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard. Double jeopardy is introduced with TOP-001 R8 and FAC-014 R5.2. Fac-014 R5.2 states "The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area"; while TOP-001 R8 states "Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis."

Response: There is no double jeopardy with separate requirements. If an entity receives a Reliability Directive and for the reasons stated in Requirement R1 can't comply with it, it is compliant with Requirement R1. If the entity fails to inform the issuer of the Reliability Directive, it is non-compliant with Requirement R2. Requirement R1 does not require the entity to inform. No change made.

As 'requested and available' is a descriptor and not separate functions. No change made.

Unless stated otherwise, a Reliability Directive should be assumed to require immediate or as soon as practicable response. The terms "immediate" and "as soon as practicable" have been debated without resolution in other projects and have been determined to be unmeasureable. The SDT sees no way to place a measurable timeframe on responding to a Reliability Directive. No change made.

The SDT sees no additional clarity from the suggested change "known or expected to be affected". This language was chosen to cover all situations, including an ongoing event. No change made. The suggested change to remove "actual" is not adopted for the same reason: An entity could be in the midst of an on-going emergency that will continue to be present in the next-day, so the wording is correct. No change made.

Organization	Yes or No	Question 1 Comment
R4: The SDT sees no additional clarity from the suggested change. No change made. This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. The subset of SOLs in this requirement requires special handling, thus, this requirement does not introduce double jeopardy. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Orange and Rockland Utilities, Inc.	No	Comments: Requirements R1 and R2 should not be separated. Having them broken out in this manner could allow entities to potentially be in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then they should break out R4 into two requirements. Who's to say that the information is requested AND available? In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency

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		as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning analysis as an analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big

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		concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard.
Response: There is no double jeopardy with separate requirements. If an entity receives a Reliability Directive and for the reasons stated in Requirement R1 can't comply with it, it is compliant with Requirement R1. If the entity fails to inform the issuer of the Reliability Directive, it is non-compliant with Requirement R2. Requirement R1 does not require the entity to inform. No change made. As 'requested and available' is a descriptor and not separate functions. No change made. This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid a noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made. The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Consolidated Edison Co. of NY, Inc.	No	Comments: Requirements R1 and R2 should not be separated. Having them broken out in this manner could allow entities to potentially be in double jeopardy when non-compliance occurs. The original language provided for a

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		very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then they should break out R4 into two requirements. Who's to say that the information is requested AND available? In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning analysis as an analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to:R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission

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		Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard.
Response: There is no double jeopardy with separate requirements. If an entity receives a Reliability Directive and for the reasons stated in Requirement R1 can't comply with it, it is compliant with Requirement R1. If the entity fails to inform the issuer of the Reliability Directive, it is non-compliant with Requirement R2. Requirement R1 does not require the entity to inform. No change made. As 'requested and available' is a descriptor and not separate functions. No change made. The SDT sees no additional clarity from the suggested change "known or expected to be affected". This language was chosen to		

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cover all situations, including an ongoing event. No change made. The suggested change to remove "actual" is not adopted for the same reason: An entity could be in the midst of an on-going emergency that will continue to be present in the next-day, so the wording is correct. No change made. The SDT sees no additional clarity from the suggested change. No change made. This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid a noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Southwest Power Pool Regional Entity	No	Action is only required by the proposed standards if a real time violation of a previously identified SOL occurs. No action is required in a preventative manner and no action is required as a result of a real time problem that was not identified by the Operational Planning Assessment. R5 should include notifying the RC of anticipated SOL violations. Addition in quotes. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact "or SOL violation" on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures

Organization	Yes or No	Question 1 Comment
		and changes in generation, Transmission, or Load.
Response: The 'anticipated' language addresses preventative. An assessment can happen at any time. It is not necessary to take action on an SOL. The definition of IROL describes the negative results that could occur when an IROL is exceeded for a time greater than its T_V. The definition for SOL does not have this language, so no "... instability, uncontrolled separation(s) or cascading outages...." happen upon the exceedance of an SOL that is not an IROL. No change made. The SDT does not agree. Adverse Reliability Impact captures the intent of the communications required in Requirement R5. No change made.		
US Army Corps of Engineers	Negative	Issue: Upon review of the NERC Glossary of Terms, please drop the from or Adverse Reliability Impacts within the definition of a Reliability Directive. Issue: M1; It is not necessary to repeat the Requirement within the Measure. Recommend unless such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1, be removed from this Measure. Issue: M4; It is not necessary to repeat the Requirement within the Measure. Recommend unless such actions would violate safety, equipment, regulatory, or statutory requirements, be removed from the Measure. Issue: Upon review, it is noted that ˜Coordination of has been struck from Purpose, however not removed from the Title of the Standard. Recommend changing ˜interconnection in the Purpose to ˜Bulk Electric System (BES) Issue: R3: The statement Transmission Operators that are known or expected to be affected the use of known or expected is redundant. Recommend removing ˜known or expected and have the requirement rewritten as follows: Issue: R3: Each Transmission Operator shall inform its Reliability Coordinator

Organization	Yes or No	Question 1 Comment
		and Transmission Operators to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. Issue: R8: The statement its internal area reliability should be clarified to state: R8: Each Transmission Operator shall inform its Reliability Coordinator of each of its SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its Transmission Operators area based on its assessment of its Operational Planning Analysis. Issue: M8: statement its internal area reliability should be clarified to state: has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis Issue: Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the SDT requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9. Note that the SOL definition has a thermal rating component in it and we are not sure how you cant draw SOLs into the same category as IROLs unless you clearly indicate these standards only apply to a subset.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration. No change made. M1 and M4: Requirement language is usually repeated in Measures. No change made. Title has been corrected. Interconnection is the correct term in the Purpose, as Transmission Operators in different interconnections are not required to coordinate actions. The SDT sees no additional clarity from the suggested change. No change made.		

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The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made.		
Bonneville Power Administration	No	Comments: Given the potential uncertainty regarding the 30 Minute Rule, BPA suggests adding more clarity to the standard TOP-001-2 as the new draft could be interpreted to mean that one would need to get the flows below the SOL immediately. BPA believes this is not practical because it takes a definite amount of time to change schedules, move generation, or perform other actions in order to reduce loadings on facilities. BPA believes the new draft should include guidance as to how much time the BA or Transmission Operator would be allowed in order to reduce flows when there is an SOL violation. BPA suggests that more clarity be provided and/or the 30 minute rule be added back to the standard.
Response: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made. Additionally, the SDT believes including the “a violation of the Facility Rating or Stability criteria upon which it is based” is superior to how the standard is written today. The currently in force TOP-004-2, Requirement R2 is written without time limits or criteria and could be interpreted as requiring flows to be mitigated immediately for an IROL and SOL as well.		
ISO/RTO Standards Review Committee	No	Instead of using ‘its’ TOP in R1 we suggest using ‘a’ TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If

Organization	Yes or No	Question 1 Comment
		this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Southwest Power Pool Reliability Standards Development Team	No	Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency

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		(N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
ISO New England Inc.	No	Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no

Organization	Yes or No	Question 1 Comment
		N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
BGE	No	BGE concurs with ISO/RTO Standards Review Committee Position:Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For

Organization	Yes or No	Question 1 Comment
		example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7.We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Pepco Holdings Inc	No	PHI supports the comments provided by the ISO/RTO Standards Review Committee.
Nebraska Public Power District	No	Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. In R3, suggest rewording as "Each Transmission Operator shall inform its Reliability Coordinator, and other Transmission Operators, of each actual and anticipated Emergency that they are known or expected to be affected by, based on its assessment of its Operational Planning Analysis". The

Organization	Yes or No	Question 1 Comment
		existing language doesn't clearly specify what is to be communicated with affected entities. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9, even in situations where the inititating event was outside of design criteria. Current language allows exceedance of an IROL for a specific time, but does not appear to give any time to readjust the system for the less severe SOLs. This does not seem reasonable. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8?This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? Suggest "Each Transmission Operator shall inform its Reliability Coordinator of each SOL identified by the Transmission Operator as supporting the reliability of its Transmission Operator Area". With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC.

Organization	Yes or No	Question 1 Comment
		Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.

Response: R1: The SDT agrees and has adjusted the language to allow for multiple TOPs.

> **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R3: The SDT does not see that the suggested change improves clarity. No change made.

R9: SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. Additionally, if the SOL was not identified in Requirement R8, then Requirement R9 does not apply to it. No change made.

R8 and R9: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. The subset of SOLs in this requirement was created in response to industry comments that SOLs should not be completely removed from the standard.

> **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R10 and R11: Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made.

R6: The SDT agrees. Conforming change made.

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

Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-

Organization	Yes or No	Question 1 Comment
003-2, Requirements R1 and R2 which will be 10 months.		
Imperial Irrigation District (IID)	No	R2 - This requirement requires the BA, GOP, and LSE to notify the TOP if it cannot comply with the Reliability Directive. (Comment) - Should include the language that the entity is not able to comply with the Reliability Directive due to violation of safety, equipment regulatory or statutory requirements. R7 - This requirement requires that the TOP not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL (Comment) - Should the language in the requirement also include the reference to SOLs since WECC does not have IROLs? R8 - This requirement requires the TOP to inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis (Comment) - Remove “which, while not IROL” from the requirement language and add “that” before “have been identified”. This would make the statement more clear. R9 - This requirement requires that the TOP not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. (Comment) - Define Continuous. What would constitute a violation? 5 minutes, 10 minutes? In some cases corrective action requires participation and/or direction from the Reliability Coordinator and this could take up to 30 minutes. Recommend leaving the 30 minute duration in place. (Comment) - Recommend referencing R7 if the SOLs are included in the requirement. R10 - This requirement requires the TOP to inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each

Organization	Yes or No	Question 1 Comment
		SOL identified in Requirement R8, has been exceeded. (Comment) - the language should include the reference to R7 if the SOL is included in the requirement. (Comment) - Recommend including ~~time frame~~timeframe for notification to the Reliability Coordinator to include "30 minutes or less" R11 - This requirement requires the TOP to act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Measures or of an SOL identified in Requirement R8. (Comment) - Since only the Reliability Coordinator has the authority to direct others to take action; should the language be revised in the following manner; "The TOP shall take action to mitigate both the magnitude and duration of exceeding an IROL or an SOL as identified in R7 and R8 that occur within its TOPs area. The TOP shall appeal to the Reliability Coordinator to direct other TOPs in mitigating both magnitude and duration on interconnected facilities on the Bulk electric System".

Response: Requirement R2 covers all situations where the Reliability Directive can't be carried out. This requirement is simply to 'inform' and at the time in question the reason is not critical. The reason can be sorted out later. No change made.

In view of the current NERC definitions of IROLs and SOLs, the language is correct as is. The definition of IROLs describes the negative results that could occur when an IROL is exceeded for a time greater than its T_v. The definition for SOL does not have this language, so no "... instability, uncontrolled separation(s) or cascading outages...." happens upon the exceedance of an SOL that is not an IROL. No change made.

The SDT disagrees and believes the requirement needs to be clear that it applies to non-IROL SOLs since IROLs by definition are a subset of SOLs. However, the language in Requirement R8 was modified for improved clarity due to other comments.

> **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

Ratings include the element of time. 'Continuous duration' has its common meaning. The SOLs in question are in reference to Requirement R8, not Requirement R7. The SDT received a substantial amount of comments during the last posting to remove the

Organization	Yes or No	Question 1 Comment
30 minute timeframe on SOLs. No change made. The SOLs in question are in Requirement R8 which is referenced in Requirement R10. No change made. Requirement R10 notification is after the fact and no timeframe is necessary. No change made. One Transmission Operator can reach out to another Transmission Operator in Requirement R11 and it would be expected that the other Transmission Operator would respond per Requirement R4. The Reliability Coordinator always maintains ultimate responsibility for multi- Transmission Operator areas as per the IRO standards and would be expected to step in as needed. This set of requirements is not a procedure. No change made.		
Kansas City Power & Light	No	Requirements R3 & R5 requires TOP's to notify all other "affected" TOP's in instances of emergency or Adverse Reliability Impact. The term "affected" is a debatable condition and subject to interpretation. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Recommend the requirement be modified to alert other TOP's whenever a TOP in an emergency or Adverse Reliability Impact operating condition becomes aware of operating conditions that would result in exceeding an SOL or IROL operating limits under N-1 contingency conditions for other TOP facilities. Modifications for these two requirements will result in subsequent changes to the Measures and VSL's for requirements R3 & R5. In requirements R9 and R11 the 30-minute transition from an unknown operating state to a known state is lost for operating from an n-1 state to a n-2 state therefore leading to an immediate violation of R9 if the facility rating is exceeded. Also, the inclusion of IROL's in R10 and R11 makes these requirements confusing as to who is responsible for mitigation, IROL's should be removed from here as they are considered in the IRO requirements, these requirements should only address SOL's. Requirement R8 uses the term "continuous duration". The term "continuous duration" will be subject to interpretation as to its meaning and intent. As proposed, this requirement will be difficult to audit and will cause

Organization	Yes or No	Question 1 Comment
		uncertainty in the industry. Also, a draft Reliability Directive definition is included in this standard but needs approval in the COM-002 standard, what if COM-002 does not get approved?
Response: The SDT believes the use of the defined terms in the requirements covers the situation appropriately. No change made. By definition an IROL violation occurs when the IROL limit is exceeded for duration greater than T_v. Thus, it must be the time duration. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made. Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made. This is actually referring to Requirement R9, not Requirement R8. 'Continuous duration' has its common meaning. No change made. Reliability Directive: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will also be coordinated with that team.		
SERC OC Standards Review Group	No	We suggest that the definition of Reliability Directive should be modified as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or “an event that results in Bulk Electric System instability or Cascading”. We also recommend that the Standard Drafting Team coordinate with the COM-002-3 Standard Drafting Team to ensure consistency in the Reliability Directive definition. We suggest the Standard Drafting Team further clarify or define the term “supporting internal area reliability” as an aid in demonstrating compliance and how this requirement enhances reliability.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>We suggest including “Real-time Assessments” in this standard to clarify Operations Planning and same day operations time horizons (Requirement 8).

We request that the drafting team review and explain the differences in the time horizons for Requirements 3, 5 and 8.</td></tr>
<tr><td colspan="3">Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration. No change made.

The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not <u>an </u>IROL<s>s</s>, <s>have</s><u>has</u> been identified by the Transmission Operator as supporting <s>its internal area</s> reliability <u>internal to its Transmission Operator Area</u> based on its assessment of its Operational Planning Analysis.

A Transmission Operator cannot operate with its IROLs (Requirement R7) and SOLs (Requirement R9) without performing Real-time assessments. As a result, the SDT does believe that Real-time assessments are included. No change made.

Requirement R3 is day ahead so the horizon is operation planning. Requirement R5 is in real-time so the horizons represent those time horizons. Requirement R8 should be Operations Planning only and the SDT has made this change.</td></tr>
<tr><td>MRO-NSRF</td><td>No</td><td>Issue: Upon review of the NERC Glossary of Terms, please drop the “s” from “...or Adverse Reliability Impacts” within the definition of a Reliability Directive.

Issue: M1; It is not necessary to repeat the Requirement within the Measure. Recommend “unless such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1”, be removed from this Measure.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		Issue: M4; It is not necessary to repeat the Requirement within the Measure. Recommend "unless such actions would violate safety, equipment, regulatory, or statutory requirements", be removed from the Measure. Issue: Upon review, it is noted that 'Coordination of' has been struck from Purpose, however not removed from the Title of the Standard. Recommend changing 'interconnection' in the Purpose to 'Bulk Electric System (BES)' Issue: R3: The statement "...Transmission Operators that are known or expected to be affected..." the use of "known or expected" is redundant. Recommend removing 'known or expected' and have the requirement rewritten as follows: Issue: R3: Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. Issue: R8: The statement "...its internal area reliability..." should be clarified to state: R8: Each Transmission Operator shall inform its Reliability Coordinator of each of its SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its Transmission Operators area based on its assessment of its Operational Planning Analysis. Issue: M8: statement "...its internal area reliability..." should be clarified to state:"...has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis..." Issue: Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the SDT requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9. Note that the SOL definition has a thermal rating component in it and we are not sure how you can't draw SOLs into

Organization	Yes or No	Question 1 Comment
		the same category as IROLs unless you clearly indicate these standards only apply to a subset.
Response: "Reliability Directive" is under the auspices of the RC SDT (Project 2006-06). This comment has been passed on to that team. Plural versions of the NERC definitions are regularly used throughout the standards. M1: Requirement language is usually repeated in Measures. No change made. M4: Requirement language is usually repeated in Measures. No change made. R3: The SDT sees no additional clarity from the suggested change. No change made. R8: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. SOLs: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made.		
Constellation Energy	No	The definition of Reliability Directive is an improvement but the definition must capture the identification concept that is reflected in the Requirement (R1). As a result, when Reliability Directive is used elsewhere, it would be clear that the communication must be identified as a Reliability Directive. We suggest the following revision to the definition and it should follow through to Project 2006-06 (COM-002-3 and IRO-001-3), eventually being added to the Reliability Standards Glossary of Terms. A communication identified as a Reliability Directive by a Reliability Coordinator, Transmission Operator, or Balancing Authority to initiate action by the recipient to address an Emergency or Adverse Reliability Impact. The revised definition should stay with each of the 3 standards until it is in the Glossary of Terms. CCG, CECD and CPG agree with ISO/RTO Standards Review Committee Position: Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is

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		possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well

Organization	Yes or No	Question 1 Comment

Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.

The SDT agrees and has adjusted the language to allow for multiple Transmission Operators.

> **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless -such actions would violate safety, equipment, regulatory, or statutory requirements.

By definition an IROL violation occurs when the IROL limit is exceeded for a duration greater than T_v. Thus, it must be the time duration. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made.

Requirement R9 does not apply to SOLs which are not identified in Requirement R8. No change made.

The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

> **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

The subset of SOLs in this requirement was created in response to industry comments. No change made.

Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made.

The SDT agrees.

> **R6**. Each Balancing Authority and Transmission Operator shall notify ~~the~~its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated

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communication channels between the affected entities. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Detroit Edison	Negative	The requirement to notify all negatively impacted interconnected NERC registered entities of planned telemetry outages is overly burdensome. Many small generators could technically be impacted, yet not very meaningful impact on a cumulative basis.
Response: The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made.		
ACES Power Marketing Member Standards Collaborators	No	We largely agree with the changes but have identified the following specific issues. We disagree with removing Bulk Electric System (BES) from the purpose of the standard. NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Substituting BES for “interconnection” in the purpose statement may solve this issue. While the title contained in the header was changed to “Transmission Operations” the actual title was not changed. They should match. For simplicity, we recommend striking “known or expected to be” from

Organization	Yes or No	Question 1 Comment
		Requirement R3. As it is written now, it is more confusing. First, the TOP, can only notify other TOPs that it knows are affected. Second, the use of “expected” implies that something different is meant than known. If so, what is the intention of the meaning and whose expectation is it: the responsible TOP, the other TOP, the auditor or some other entity? There is a similar issue regarding “known or expected to result in an Adverse Reliability Impact” in Requirement R5. We recommend striking “or expected” for simplicity and to avoid the confusion of whose expectation it is. In Requirement R8, “while not IROLs” should be “while not an IROL”. We agree with removing the 30 minute limit in Requirements R9 and R11 and basing the time limit upon the Facility Rating or Stability criteria. In Requirement R10, striking “each” before SOL would improve the clarity of the requirement. In Measurement M1, “nless” should be unless. This may already be correct. The red-lines show “nless” and the clean document shows “unless”. What is the intended difference between Transmission Operator Area in Requirement R5 and internal area in Requirement R8? Should they be the same and if not why not?
Southwest Transmission Cooperative, Inc.	Affirmative	We disagree with removing Bulk Electric System (BES) from the purpose of the standard. NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader

Organization	Yes or No	Question 1 Comment
		than the BES, we would like to see BES inserted back into the purpose statement. Substituting BES for "interconnection" in the purpose statement may solve this issue. While the title contained in the header was changed to "Transmission Operations" the actual title was not changed. They should match. For simplicity, we recommend striking "known or expected to be" from Requirement R3. As it is written now, it is more confusing. First, the TOP, can only notify other TOPs that it knows are affected. Second, the use of "expected" implies that something different is meant than known. If so, what is the intention of the meaning and whose expectation is it: the responsible TOP, the other TOP, the auditor or some other entity? There is a similar issue regarding "known or expected to result in an Adverse Reliability Impact" in Requirement R5. We recommend striking "or expected" for simplicity and to avoid the confusion of whose expectation it is. In Requirement R8, "while not IROLs" should be "while not an IROL". We agree with removing the 30 minute limit in Requirements R9 and R11 and basing the time limit upon the Facility Rating or Stability criteria. In Requirement R10, striking "each" before SOL would improve the clarity of the requirement. In Measurement M1, "nless" should be unless. This may already be correct. The red-lines show "nless" and the clean document shows "unless". What is the intended difference between Transmission Operator Area in Requirement R5 and internal area in Requirement R8? Should they be the same and if not why not?
Response: BES: The purpose of the standard is to address reliability needs. Any concerns about BES vs. BPS in standards are		

Organization	Yes or No	Question 1 Comment
better directed toward the Standards Committee. No change made. Title: Conforming change has been made. R3: The SDT sees no additional clarity from the suggested change. No change made. R5: The SDT sees no additional clarity with the suggested change "known or expected to be affected". This language was chosen to cover all situations, including an ongoing event. No change made. R8: The SDT agrees. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. The SDT thanks you for your support on removal of the 30 minute limit. R10: The SDT agrees and made the conforming change. **R10**. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or ~~each~~an SOL identified in Requirement R8, has been exceeded. M1: This has been corrected. In response to this and other comments, Requirement R8 has been edited to match the language in Requirement R5.		
Lincoln Electric System (LES)	No	R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included a provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't

Organization	Yes or No	Question 1 Comment
		identified in R8? R8 is unclear as currently drafted. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation.
Response: R7 and R9: By definition an IROL violation occurs when the IROL limit is exceeded for a duration greater than T_V. Thus, it must be the time duration. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made. Requirement R9 does not apply to SOLs which are not identified in Requirement R8. No change made. R8: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. R8 and R9: The subset of SOLs in this requirement was created in response to industry comments, resulting in no conflict with the purpose of the standard. No change made. R10 and R11: Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to		

Organization	Yes or No	Question 1 Comment
handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made. R6: The SDT agrees. **R6**. Each Balancing Authority and Transmission Operator shall notify ~~the~~its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Progress Energy	No	Progress, while supporting what we believe is the overall intent of this Standard revision, cannot support an affirmative vote on TOP-001-2. Progress appreciates the efforts of the SDT and offers the following suggestions: In R8 it remains unclear what is meant by the phrase "supporting its internal area reliability." Clarity and unambiguous language is needed here so that entities can clearly understand and comply with the requirement. Progress understands from reading the most current "Consideration of Comments" that the Standard Drafting Team left this phrase intentionally undefined; however, the inclusion of this phrase means that in an audit scenario there could be a disagreement about what "supporting its internal area reliability" means. This has the potential to negatively impact the compliance position of the Transmission Operator. In R9 it is unclear what is meant by a "continuous duration that would cause a violation..." Some entities may have facility ratings that are time based, while other entities take the position that the exceedance of a facility rating for any amount of time means an SOL violation. A suggested change in wording would be to simplify the requirement to read "Each Transmission Operator shall not operate outside any SOL indentified in Requirement R8 that would cause a violation of the Facility Rating or Stability criteria upon

Organization	Yes or No	Question 1 Comment
		which it is based." Progress suggests changing R10 to read "Each Transmission Operator shall inform its Reliability Coordinator of the mitigation actions it has taken or directed to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded." The current draft language implies that the TOP must only inform the RC of "...its actions..." Progress suggests switching the order of the current R10 and R11; from reading the most current "Consideration of Comments" it seems that the actions required in R8-R11 are intended to be sequential. Progress suggests that switching the order of the current R10 and R11 would make it easier for a reader to understand that these are intended to be sequential actions.
Response: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. Ratings include the element of time. Continuous duration' has its common meaning. The phrase "for a continuous duration" was added in response to industry comments. No change made. The SDT believes the requirement mandates that the Transmission Operator inform of any actions which would include directions to others and sees no additional clarity with the suggested change. No change made. This is not a procedure and the order of the requirements doesn't matter. There is no additional clarity provided by the suggested change. No change made.		
LG&E and KU Serivces	No	LG&E and KU Services believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This

Organization	Yes or No	Question 1 Comment
		is a Reliability Directive." to avoid any possibility of confusion.
Response: The definition does not include the regulated action. Requirement R1 states that it must be identified. The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.		
City Water Light and Power (CWLP) - Springfeild – IL	No	R8 requirement to identify "...SOLs which...have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis" is vague and difficult to measure. "Internal area reliability" could conceivable include all SOLs CWLP echoes SERC Operating Committee comments submitted separately:" We suggest that the definition of Reliability Directive should be modified as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or "an event that results in Bulk Electric System instability or Cascading". We also recommend that the Standard Drafting Team coordinate with the COM-002-3 Standard Drafting Team to ensure consistency in the Reliability Directive definition."
Response: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. If the Transmission Operator believes it needs to include all of its SOLs, the requirements do not preclude them from doing so. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.		
United Illuminating Company	No	R3 phrase "known or expected to be affected by each actual and anticipated

Organization	Yes or No	Question 1 Comment
		Emergency based on its assessment of its Operational Planning Analysis" is confusing. Glossary defines emergency as Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. Glossary defines Operation Planning analysis as An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints(transmission facility outages, generator outages, equipment limitations, etc.).I do not see the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to effected by an anticipated Emergency. Those TOP's known to be effected are part of the group expected to be effected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. Along the thought the Time Horizon in the Requirement is Operations Planning. I suggest rephrasing this requirement as:R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Comment for R8. It seems that double jeopardy is introduced with TOP-001 R8 and FAC-011 R5.2. Fac-011 R 5.2 states The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area; while TOP-001 R8 states R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal

Organization	Yes or No	Question 1 Comment
		area reliability based on its assessment of its Operational Planning Analysis.
Response: The SDT sees no additional clarity with the suggested change. No change made. The subset of SOLs in this requirement requires special handling (an incremental requirement to FAC-014-2, Requirement R5.2), thus, this requirement does not introduce double jeopardy. While FAC-014-2, Requirement R5.2 requires the Transmission Operator to provide all of the SOLs it developed to the Reliability Coordinator, proposed TOP-001-2, Requirement R8 requires the Transmission Operator to further sub-divide those SOLs into those that require special handling in this standard. No change made.		
California Independent System Operator	No	R6 requires Balancing Authorities and Transmission Operators to notify "negatively impacted interconnected NERC registered entities" of planned outages. This term is not specific enough to narrow down who must be notified. For instance, with this open-ended wording it could be construed that BAs would have to notify LSEs and DPs in their areas which would be an onerous task. We would recommend staying with "negatively-affected BAs and TOPs." The wording in R9 is confusing and is not specific enough to ensure compliance. In particular the requirement prohibits operation outside any SOL "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based." However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. In addition, under R9 and M9, how will the word "continuous" be defined or measured? This is extremely important to understand because the VSL table states the following as Severe for R9: "The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria." It seems that the effective date should be set much sooner than 24 months following approval since there are basically no new requirements associated

Organization	Yes or No	Question 1 Comment
		with this standard. Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Response: R6: The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made. R9: 'Continuous duration' has its common meaning. No change made. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
We Energies	No	R3's wording is incomplete. It requires informing and states who must be informed but does not state what must be told. The bulk of the requirement is a description of which RCs and TOPs must be informed, but lacks informing the TOP's BA(s) of an Emergency. Should also include the BA informing its RC and TOP(s) R4 It is not clear what emergency assistance a TOP can provide? Most actions would involve moving a generator or shedding load, the few items a TOP can do independently like returning a line from outage, or switching reactive devices should be done as a matter of course. R5 The bulk of the requirement is a description of which RCs and TOPs must be informed, but lacks informing the TOP's BA(s) of an operation resulting in an Adverse Reliability Impact. Should also include the BA informing it's RC and TOP(s) R6 is overly broad. Every entity in an interconnect can be negatively impacted somehow. The requirement should be focused on the operational

Organization	Yes or No	Question 1 Comment
		entities of the TOP, BA and RC. These are the entities that specify the data that must be made available see IRO-010, proposed TOP-003 from others. Individual asset owners provide data to the operators and when the operators plan an outage they should let the other affected TOP, BA and RC know its to happen. R8: change "have" to "has". The associated measures should be updated to reflect the above. Data Retention: The second paragraph states that Measures must be complied with. Compliance with measures cannot be required.

Response: R3: The SDT does not see that the suggested change improves clarity. The requirement indicates that the recipients must be told about the effect on them of an actual or anticipated emergency. No change made.

R4: The Transmission Operator has actions that it may take or direct such as switching, bringing on capacitor banks, delaying maintenance, etc. All of these are possible emergency assistance actions.

R5: Requirement R5 is for transmission so the Balancing Authority can't be included (Balancing Authority's have no transmission information). No change made. Approved EOP-002-3, Requirement R3 covers the situation for a Balancing Authority needing to inform others of impacts. No change made.

R6: The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made.

R8: The SDT agrees.

> **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

Measures: Conforming changes were made to measures.

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Data Retention: The SDT agrees and has deleted the compliance phrasing.		
American Transmission Company, LLC	No	o If the definition of "Reliability Directive" remains, the Definitions of Terms Used in the Standard should note that there is in fact a new or revised definition. ATC agrees with the definition. o Requirement 4 - This should have a control by the Reliability Coordinator to ensure that a Transmission Operator in distress has, in fact, implemented their "comparable emergency procedures". o Requirement 5 - ATC does not agree with removing the BA from this requirement since they make note that it will be addressed in another, "proposed" requirement as stated in the mapping document. o Requirement 7 - Real-Time EMS representation of IROL Tv, will require an unidentifiable amount of resources. o Requirement 9 - SOL's should have a time requirement. Also, they should not be raised to the level of IROL's as may be insinuated by this requirement if they are discretionary, as noted in Requirement 8. o Requirement 11 - If this requirement entails the issuing of a "Reliability Directive", it should be stated as such.
Response: Reliability Directive: This standard does identify this definition as a new definition that is being developed by Project 2006-06. It also mentions that the RTO SDT is coordinating with that project. R4: In the context of mandatory standards, no Reliability Coordinator control is needed. No change made. R5: The Balancing Authority did not appear in Requirement R5 so the SDT does not understand the comment. No change made. R7: It is common practice in the industry to have ratings with both magnitude and duration. The SDT understands that there are relatively few IROLs, and does not expect a significant burden on the Transmission Operator to be able to comply with this requirement. Also, the requirement does not dictate the technological tools used in assuring compliance. No change made. R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. Some SOLs are based		

Organization	Yes or No	Question 1 Comment
off of Facility Ratings and, thus, include the time dimension. It is to the Transmission Operator's discretion to select the appropriate SOLs in Requirement R8 that it feels need to be treated like this. No change made. R11: This requirement does not have to specify how an instruction is issued. No change made.		
Omaha Public Power District	No	OPPD is concerned with Requirements (R8 and R9) related to System Operating Limits (SOLs). We would like to ask the SDT to clarify what the word "continuous duration" means in terms of timing. We understand the "continuous duration" is based on Facility Rating or Stability criteria, however, without any defined time frame, the term "duration" would be subject to variety of interpretations. OPPD supports a time window to allow TOP to return from SOL similar to IROL Tv.
Response: SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. 'Continuous duration' has its common meaning. It is to the Transmission Operator's discretion to select the appropriate SOLs in Requirement R8 that it feels need to be treated like this. No change made.		
Manitoba Hydro	No	R1 - Manitoba Hydro suggests that the first instance of 'identified' in R1 be removed as it is redundant given that R1 already specifies that the Reliability Directive is 'identified as such'. As drafted, the standard suggests that there is a difference between an 'identified Reliability Directive' and a 'Reliability Directive'. Data Retention (1.3) – The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified logs, recordings and emails, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. This comment applies to TOP-001-2, TOP-002-3, and TOP-003-1.

Organization	Yes or No	Question 1 Comment
Response: The SDT agrees and has deleted the first instance of 'identified'. **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless -such actions would violate safety, equipment, regulatory, or statutory requirements. Data Retention: The language in the 1st paragraph is boilerplate that is inserted in all standards. Compliance language is not under control of SDT. No change made.		
Texas Reliability Entity	No	In R1, the phrase "and identified as such" is redundant and unnecessary in that "identified" already exists within the sentence. Furthermore, the addition of the word "identified" or phrase "identified as such" inserts undue ambiguity and complication, and we are concerned that the "identified" concept will actually provide more opportunities for miscommunications during tense situations. In R1, we are concerned that "Directive" is being proposed with descriptive terms (e.g., "reliability"), and if the descriptive terms are not used explicitly an entity may not be compelled to act accordingly (also may provide leverage for a perceived loophole in compliance activities that could be exploited-"I was unaware it was a {insert descriptive term} Directive"). There should be a time frame associated with requirement R2. Perhaps add "within the timeframe determined for the Directive being issued" to end of sentence. Also, we suggest removing "identified" from requirement R2 (see comments on R1). oThere should be a time frame associated with the communication required by Requirement R5. oR5 should explicitly include IROL, SOL, and Stability Limit violations in the examples since the proposed definition of Adverse Reliability Impact implies

Organization	Yes or No	Question 1 Comment
		instability and Cascading outages. oWe suggest rewriting R5 as follows: "Each Transmission Operator shall inform its Reliability Coordinator and other affected Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas within a timeframe that is sufficient for the RC and affected TOP's to respond to the system condition, unless conditions do not permit such communications. Such operations may include, but are not limited to, Interconnection Reliability Operating Limit (IROL) violations greater than Tv, System Operating Limit (SOL) violations, Stability Limit violations, relay or equipment failures, and changes in generation, Transmission, or Load." In R9, the use of "continuous duration" in the revised language is confusing and should be removed. It would be better to clearly rely on the other standards that relate to identifying IROLs and SOLs (including duration limits), which may have multiple time limits associated with various operating conditions. We note that an SOL may not be based on a single Facility Rating but may actually be a group of Facilities aggregated into a single limit. We suggest saying: "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria, including duration, upon which it is based".

Response: The SDT agrees and has deleted the first instance of 'identified'.

> **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless ~~-~~such actions would violate safety, equipment, regulatory, or statutory requirements.

Some instructions are more important than others. In order to separate these more important instructions from those for routine actions, the descriptive 'adjective' is required so that the receiving entity understands the importance of the instructions. Reliability Directives are of such importance that the actions taken must conform exactly to the instructions as opposed to routine operating instructions which may allow for some discretion. If this isn't made clear during the event, then it is not a Reliability

Organization	Yes or No	Question 1 Comment
Directive. This is not a loophole and is consistent with the recent Board of Trustees adopted interpretation of COM-002-2 that makes clear that directives are intended for emergencies only. No change made. The Reliability Directive in question will include the timeframe for the response if one is needed. No change made. The term 'identified' was included in Requirement R2 in response to industry comments that all Reliability Directives must be identified as such. No change made. This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made. R5: The examples are not types of violations but types of operations. No change made. R9: 'Continuous duration' has its common meaning. No change made.		
New York Independent System Operator	No	Communications must be a well defined, consistent and established process to promote clear and accurate communications between operators for both normal and emergency conditions. This standard could be interpreted as to require an extra phrase during emergencies that would unnecessarily complicate communications. The requirement is reasonable if the identification of a 'Reliability Directive' may be done in a policy or procedure that is communicated to the BA, GOP, DP or LSE as a communication protocol that addresses normal and emergency communications. Otherwise requiring different verbal communication protocols for normal or emergency conditions will add a level of risk currently not observed.
Response: The SDT disagrees that including a simple statement that this is a Reliability Directive complicates communications. In fact, the SDT thinks it improves communications because the recipient understands it must follow the Reliability Directive explicitly. There is nothing in this standard that prevents an entity from adopting formal communication protocols to always identify directives as such to ensure consistent and uniform communications. No change made.		

Organization	Yes or No	Question 1 Comment
Xcel Energy	No	R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity informs its Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. We would like to see additional clarification to clarify “equipment”, suggest using “equipment limitation” or “equipment rating” R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. This requirement should be modified so as not to place the burden on the assisting entity to demonstrate that the requesting entity has implemented “comparable emergency procedures”. Suggest the following language: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment ratings, regulatory, or statutory requirements. R5. Each Transmission Operator shall inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. This requirement appears to duplicate PRC-001-1 R2 and R5. It is assumed, but cannot be verified that those requirements will be eliminated in a future approved version of that standard. R9 - We appreciate the drafting team’s efforts. However, we are still concerned that R9 will not allow the Transmission Operator the flexibility to identify the best SOL recovery approach, without incurring a violation of the

Organization	Yes or No	Question 1 Comment
		requirement. Instead, the TOP may be forced to shed load in order to avoid violating the requirement. This is not ideal, especially when the situation could be mitigated successfully with alternative measures. It is not clear if an entity is allowed to use an RC-approved contingency plan to mitigate a situation that would cause a Facility Rating violation (i.e. the Facility Rating is the SOL), without also incurring a violation of R9. To further explain, if an entity foresees exceeding an SOL in its OPA, and obtains approval from the RC on their proposed contingency plan (which includes a Facility Rating violation), will that entity be considered in violation of R9 once the exceedance occurs and the contingency plan is implemented? R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. This requirement should specify a sustained period which establishes when it is considered that the entity has returned below the limit (or some other value so as to not misconstrue momentary recoveries as meeting this requirement).

Response: R1: All terms are descriptors of the word 'requirements' so the SDT believes that your concerns have been met with the existing language. No change made.

R4: Industry comments caused the SDT to insert the 'comparable' language. No change made.

R5: The SDT is proposing to retire PRC-001-1 Requirements R2, R5, and R6. A redline of PRC-001-1 will be posted with these comments.

R9: Ratings include the element of time, that is, ratings are two dimensional, with a magnitude limit and time (duration) limit. 'Continuous duration' has its common meaning. The flexibility remains within these requirements to have a mitigation plan in place. However, the mitigation plan must avoid causing a ratings violation (avoid exceeding the magnitude limit for greater than T_v), else, it would be a violation of this requirement. No change made.

R10: Requirement R10 is about actions taken by the Transmission Operator and not about relief attained. That is covered in the IRO standards. Therefore, no change is necessary.

Organization	Yes or No	Question 1 Comment
ReliabilityFirst	No	ReliabilityFirst has the following comments for consideration: 1. Definition of Reliability Directive - ReliabilityFirst believes there could be a possible issue with the definition of "Reliability Directive" being developed and approved via another drafting effort (i.e. Project 2006-06). In the hypothetical situation where the TOP-001-2 standard is approved and the definition of "Reliability Directive" is drastically changed through the Project 2006-06 effort, there could possibly be a disconnect between the TOP-001-2 requirements and the "Reliability Directive" definition. Also, ReliabilityFirst recommends adding a parenthetical "(e.g. IROL or SOL violations)" to the end of the definition for further clarity. 2. R2 - There is no time qualifier specified in R2 dealing with the timeframe in which the applicable entity has to inform its Transmission Operator of its inability to perform an identified Reliability Directive. ReliabilityFirst recommends the SDT consider adding language to include a timeframe for the entity to inform the Transmission Operator (such as one hour). Absent any specified timeframe, an applicable entity could hypothetically inform its Transmission Operator of its inability to perform an identified Reliability Directive 30 days after the Reliability Directive was issued, and still be compliant based on the current words of the requirement. 3. R4 - The term "emergency" is used within this requirement and ReliabilityFirst seeks clarification on whether this is referring to the NERC definition of "Emergency" (as defined in the NERC Glossary of terms)? If so, this term should be capitalized. 4. R5 - The last sentence in R5 is not really a requirement, but rather a measure on how to comply with the requirement. ReliabilityFirst recommends deleting the last sentence of R5 and incorporating it into the corresponding Measure. 5. R6 - ReliabilityFirst recommends removing the term "negatively impacted

Organization	Yes or No	Question 1 Comment
		interconnected NERC registered entities" and replace it with the associated functional entities (e.g. Balancing Authority, Generator Operator, etc.). 6. R8 - ReliabilityFirst recommends removing the term "while not IROL's" from R8. SOL is a NERC defined term and the extra qualifier is not needed. 7. R10 and R11 - ReliabilityFirst recommends swapping the order of R10 and R11. From a chronological standpoint, the Transmission Operator will "act or direct others to act, to mitigate..." (R11) prior to "informing its Reliability Coordinator of its actions" (R10). 8. Data retention - ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example, the last sentence states "the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.

Response: Reliability Directive: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team also. This comment will be passed to that team for consideration.

The Reliability Directive in question will include the timeframe for the response if one is needed. No change made.

The NERC defined term "Emergency" was not the intent of this requirement. In this requirement, 'emergency' means actions taken quickly in response to an immediate need. No change made.

The last sentence in Requirement R5 is intended to provide guidance on the kinds of operations that should be communicated and is better kept in the requirement. No change made.

If the entities were listed, the list would include every NERC functional entity that has telemetry. This change would not improve

Organization	Yes or No	Question 1 Comment
reliability. No change made. IROLs are a subset of SOLs as defined by NERC. The requirement concerns a different subset of SOLs. No change made. This is not a procedure and the order of the requirements doesn't matter. There is no additional clarity provided by the suggested change. No change made. Data Retention: The language in the 1st paragraph is boilerplate that is inserted in all standards. The compliance language is not under control of SDT. No change made.		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agecy supports comments submitted by the SERC OC Standards Review Group and the ISO/RTO Standards Review Committee concerning the need to address the "Reliability Directive" definition in concert with COM-002-3.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.		
Duke Energy	No	While the drafting team has made several improvements to this standard, we believe these additional changes are needed: o The definition of Reliability Directive includes the defined term "Adverse Reliability Impact", which should be replaced by the actual wording of latest BOT-approved definition of "Adverse Reliability Impact", since it has not yet been approved by FERC. If the SDT decides not to replace Adverse Reliability Impacts with the actual wording of the latest BOT-approved definition, then the SDT should delete the "s" from "Impacts". o R8 - We believe that the phrase "supporting its internal area reliability" should be further clarified in some way. The inclusion of the undefined concept of "supporting internal area reliability" creates undue compliance risk, since auditors could potentially find an entity non-compliant if no SOLs have been identified as "supporting its internal area reliability". The drafting team could examine the disturbance reporting criteria in EOP-004-1

Organization	Yes or No	Question 1 Comment
		Attachment 1 to help develop a reasonable threshold for reporting SOLs to the Reliability Coordinator. o R8 - Consistent with R3, the Time horizon for R8 should only be Operations Planning. o R9 - The change that has been made to R9 could be interpreted to result in a violation if a facility rating is exceeded for any amount of time at all. Similar to an IROL's Tv, SOLs identified under R8 should have an identified time period (such as 30 minutes) for mitigation without a violation. A change to R9 should be coupled with development of a reporting threshold for R8 as discussed above. o M1 - typo, left the "u" off the word "unless". o Measures for R8 and R9 should be changed consistent with our suggested revisions to the requirements.

Response: "Reliability Directive" is under the auspices of the RC SDT (Project 2006-06). This has been passed on to that team.

R8: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

> **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R8: The SDT agrees and has changed the Time Horizon to Operations Planning.

R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made.

M1: This has been corrected.

Organization	Yes or No	Question 1 Comment
M8 and M9: Conforming changes were made to Measure M8. No changes were made to Requirement R9.		
South Carolina Electric and Gas	No	Please provide clarity on the phrase "support its internal area reliability" in R8.
Response: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Oklahoma Gas and Electric	No	A. In the draft TOP-001-2 standard, R1 and R2 both address complying with Reliability Directives. OG+E suggests these two requirements be combined into one requirement using similar language found in other standards that contain the same Reliablity Directive requirement, such as IRO-001-1.1 R8 and the previous version of this standard for consistency purposes. B. Mitigation of IROLs is ultimately the responsibility of the RC. TOPs act under the direction of the RC when mitigating IROLs. TOP-001-2 R11 should clarify by adding the following to the beginning of the requirement. "Under the direction of the RC, each TOP shall act or direct others to act...". C. Please clarify the meaning of "internal area realiability" in R8. D. In R9, "continuous duration" warrants additional clarification. Is this 5, 10, 30, 60 minutes of operating outside the SOL? Or only continuous operation outside of SOL that results in ultimately exceeding the Facility Rating?

Organization	Yes or No	Question 1 Comment
Response: R1 and R2: The SDT sees no additional clarity with the suggested change. No change made. R11: Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made. R8: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. 'Continuous duration' has its common meaning. No change made.		
American Electric Power	No	R7, R9, R10, & R11 - It needs to be clarified whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumes this is based on Real Time Flow, however we encourage the drafting team to provide clarifying language to make it more clear to the reader. Taken together, the combination of R7 and R9 appears redundant with R11, as meeting the objective of R7 and R9 would imply taking the proper mitigating measures. AEP suggests either eliminating both R7 and R9 or eliminating only R11. If r7 and R9 were to be eliminated, the references to magnitude and duration should be removed from R11, as the associated measure is binary

Organization	Yes or No	Question 1 Comment
		in respect to the limit, i.e., either the limit has been exceeded or it has not. It would be premature for AEP to support the associated VSLs and VRFs given the objections stated above.
Response: R7, R9, R10, and R11: The SDT agrees for SOLs, however, it must be noted that IROLs have been defined as both pre-contingent and post-contingent. The exact definition of the IROL must be honored. No change made. R7, R9 and R11: These requirements are the core Transmission Operator requirements that assure continued reliable operation of the BES. If the Transmission Operator acts or directs others to act to mitigate, as in Requirement R11, but the facility remains in violation of Requirements R7 or R9, then the Transmission Operator is compliant with Requirement R11 and noncompliant with either Requirements R7 or R9, as dictated by the exact circumstances. If the Transmission Operator fails to act or fails to direct others to act, as in Requirement R11, then it is noncompliant with both Requirement R11 and either Requirement R7 or R9, as dictated by the exact circumstances. This is not double jeopardy. No change made.		
PPL Electric Utilities	No	We believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This is a Reliability Directive." to avoid any possibility of confusion.
PPL EnergyPlus LLC	Affirmative	We believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This is a Reliability Directive." to avoid any possibility of confusion.
Response: The definition does not include the regulated action. Requirement R1 handles the action. Compliance is measured against requirements, not definitions. The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration. No change made.		
Ameren	No	R2. When is “shall inform” to occur; timely, promptly, ... It would be injurious to BES reliability for the TOP to get such information, say 15 minutes or half-hour later as many other things are likely to be put in place on the assumption the directive is “ok”. R3. The wording is incorrect it implies the TOP will notify the RC and its

Organization	Yes or No	Question 1 Comment
		TOP's. The word other may be missing. But even with other the question it begs which other TOP's? It could be argued that the RC only needs to know Emergencies that are both actual and anticipated. They would want to know about them whether they are actual or anticipated. This direction here is not clear; it may be helpful to use two sentences to address and clarify the issues of this requirement. R4. What is meant by emergency assistance is not clear; clarify and provide examples. Is it emergency energy? Is it emergency food? Is it emergency crews? This ambiguity is a compliance nightmare as you have to prove you have everything covered that could loosely be interpreted as emergency assistance. If the SDT has an idea what they are expecting, it should be listed. If they don't have an idea of what constitutes emergency assistance, then we recommend removing it from the Requirement. R5. The Requirement should be re-written to say "Each TOP shall inform only if it adversely affects others its RC and other TOP's (Which other TOP's? This direction here is not clear; clarify) of its operations known or expected to result in an Adverse Reliability Impact ..." R6. What is meant by negatively impacting is not clear; clarify and provide examples. For example, using the words as listed, economic impact might be a consideration. The Standard should not be setting up a condition where TOPs tell GO/GOPs that they might suffer economic harm as a result of one of the communication channels being down. As currently worded this might lead to a civil issue instead of a BES reliability issue. R8. There are SOLs that are developed in real-time (as evidenced by the multi-time-horizon assigned). It might be possible for such an SOL to develop and have to be resolved for local area reliability only, before the RC could be notified. This Requirement should insert the word planned before SOL. Alternatively, insert where time permits in place of real-time.

Organization	Yes or No	Question 1 Comment
		R9. What is meant by continuous duration is not clear; clarify. Is it 5 minutes, 15 minutes, an hour, a day? Anything more than 5 minutes is likely to be in the thermal time-constant period where rating could be affected. We feel that the real intent of this requirement is that TOPs resolve SOLs. It is not so much how long, as it is that they are not purposely delaying the resolution. The Requirement should be re-written to say "The TOP's will resolve as soon as possible anys SOL...... with no intentional time delay..." R10. The Requirement as written should be prefaced with "when time permits, each Transmission Operator....." The idea of time permitting is alluded to in R5, "unless conditions do not permit such communications".

Response: R2: The Reliability Directive in question will include the timeframe for the response if one is needed. No change made.

R3: The word 'other' is not required. The language following Transmission Operator confines the set of which Transmission Operators. No change made.

R4: The NERC defined term "Emergency" was not the intent of this requirement. In this requirement, 'emergency' means actions taken quickly in response to an immediate need. No change made.

R5: The requirement has the Transmission Operator with the issue limited to notifying those "other Transmission Operators" whose Transmission Operator Areas are expected to have an Adverse Reliability Impact. No change made.

R6: NERC requirements are concerned only with reliability of the BES, not economic harm. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made.

R8: The key phrase in this requirement is 'based on its assessment'. No change made.

R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. 'Continuous duration' has its common meaning. No change made.

Organization	Yes or No	Question 1 Comment
R10: Requirement R5 allows for the possibility of a suddenly developing condition. Requirement R10 is concerned with the reporting of actions after they occur. No change made.		
Tacoma Public Utilities	Affirmative	We would like to request that specific definitions are included for the individual time horizons. We suggest the following potential definitions: 1. Same Day Operations - Routine actions required within the time frame of a day, but not real-time. 2. Real-time Operations - Actions required within one hour or less to preserve the reliability of the bulk electric system. 3. Operations Assessment - Follow-up evaluations and reporting of real-time operations.
Response: These are defined in the NERC SDT Guidelines. No change made.		
NIPSCO	Yes	In R8 consider changing "internal area" to "Transmission Operator Area" In R9 consider clarifying "continuous duration", what is that?
Response: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. 'Continuous duration' has its common meaning. No change made.		
Georgia System Operations	Yes	GSOC agrees in general but feels that some clarity should be provided. The purpose of the language "each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area

Organization	Yes or No	Question 1 Comment
		reliability based on its assessment of its Operational Planning Analysis" (OPA) is not clear. Is the intent to clarify the meaning of SOL? If so the definition in the glossary should be updated to clarify the meaning and the clarification should be removed whenever used in TOP-001, 002, or 003. Is the intent to limit which SOLs are being referred to? Not each SOL but each SOL which have been identified as supporting the internal area reliability based on the assessment of its OPA. Could this language be deleted and still convey what is required?
Response: The SDT disagrees that the phrase is not clear. It is identifying SOLs that the Transmission Operator feels are important enough to request that they be monitored similar to an IROL. This could occur for any number of reasons. No change made.		
Associated Electric Cooperative, Inc.	Yes	R3 Guidance Add: A Guidance Section for Requirement R3 clarifying “anticipated Emergency” - AECI believes the SDT should draft guidelines as to what “anticipated Emergency” means within this requirement. That guidance should also caution against dumping information (data-overload) upon neighboring parties, for trivial impacts to their system. Rationale: In earnest to avoid non-compliance with R3, entities could blast their neighbors with all changes, regardless of impact, and then the purpose of this requirement will be lost.) R6 Requirement wording Change: “negatively impacted” To: “known negatively impacted” Rationale: While 1st hand affected parties are likely known, secondarily affected parties might pose a compliance problem. R8 Guidance Add: An R8 Guidance section Rationale: AECI’s understanding is that our providing our RC with AECI’s most-limited-element equipment seasonal operating limits and short-term limits, where applicable, meets this requirement. If we are wrong, then additional guidance is definitely necessary.
Response: The requirement is limited by the fact that actions are based on your assessment of the Operational Planning		

Organization	Yes or No	Question 1 Comment
Assessment. No change made. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. The Transmission Operator must comply with FAC standards for proper definition of SOLs. An SDT cannot give compliance advice.		
Dairyland Power Cooperative	Yes	Concern re R5. The determination of when an operating condition could be "expected to result in an Adverse Reliability Impact" would be difficult and ambiguous.
Response: The Transmission Operator is in the best position to know if other areas may suffer an Adverse Reliability Impact. The examples cited in the requirement: “Such operations may include relay or equipment failures and changes in generation, Transmission, or Load” are intended to give guidance. No change made.		
NV Energy	Yes	Yes, however, there are a few points to note: Part A, Section 1 continues to title this standard as "Coordination of Transmission Operations, while the header of the Standard was changed to simply "Transmission Operations". The requirements R6 and R8 appear to be outside the realm of real-time operations, R6 dealing with planned outages of telemetry, comm, and control equip, and R8 dealing with communication of SOL's or other limits. It is confusing to mix in Operations Planning type requirements in a standard that otherwise deals with real-time grid operations. Suggest relocating these two to the Operations Planning Standard, TOP-002-3.
Response: Title: Conforming change has been made. R6 and R8: Telemetry outages may be planned for the same day or in the next hour. SOLs may be affected in similar timeframes (new topology forcing a readjustment of the system, for instance). No change made.		

Organization	Yes or No	Question 1 Comment
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	From the GO/GOP perspective, Ingleside Cogeneration LP believes that the SDT has captured the appropriate circumstances for when a Reliability Directive is issued and identified - and the circumstances under which it may be not be possible to accommodate one.
US Bureau of Reclamation	Yes	
Westar Energy	Yes	
FirstEnergy	Yes	
Dominion	Yes	
PacifiCorp	Yes	
Western Area Power Administration	Yes	
FMPP	Yes	
Luminant Energy Company, LLC	Yes	
Independent Electricity System Operator	Yes	
Response: Thank you for your support.		

2. **The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: There were four common concerns expressed in the comments.

First, the "rationale box" for Requirement R1 was eliminated. The SDT agreed that the rationale offered was inappropriately addressing more of a compliance issue than explaining the background reasoning.

Second, commenters questioned the use of Facility Ratings and Stability Limits in Requirement R1 rather than the use of the terms Interconnection Reliability Operating Limit and System Operating Limit. The SDT prepared responses to clarify the reasoning for the use of Facility Ratings and Stability Limits, but did not change the wording of the requirement.

Third, the commenters questioned the use of the phrase "internal area reliability" in Requirement R2. The SDT revised Requirement R2 to change the phrase from "internal area reliability" to "reliability internal to its Transmission Operator Area" to clarify that the requirement is related to a Transmission Operator Area, which is a defined term, and that it is a reliability concern within that area, not one that concerns other areas nor does it rise to the level of adversely affecting the reliability of a wider area ~~or~~ of the Bulk Electric System.

Fourth, some commenters expressed concern about Requirement R3 and the notifications of entities which are identified as having roles in operating plans developed by the Transmission Operator in Requirement R2. The concern was related to whether the notifications may conflict with confidentiality requirements. The SDT explained that the notifications are simply to alert the entities that they have been identified as having roles in the operating plans to address reliability issues, but that such notifications do not have to include specifics about what the plan is to address. The entity may know that it may be called upon to perform its role of switching, changing of generator output, or other similar actions, but no specific information would be issued that may result in the unintended consequence of giving any entity "market power" or other competitive advantage.

The SDT has made no substantive changes to the requirements of TOP-002-3. However, Requirement R2 was clarified as follows:

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

Organization	Yes or No	Question 2 Comment
Muscatine Power & Water	Negative	First and foremost is the Requirement in TOP-002-3 for having a process for performing an "Operational Planning Analysis." That term, "Operational Planning Analysis," does not have a FERC-approved definition. The definition floating around at NERC implies some sort of simulation (with or without a tool) being perform next-day to determine exceedence of facility ratings or stability limits.
Response: The definition of Operational Planning Analysis was approved by FERC in March 2011.		
New Brunswick Power Transmission Corporation	Negative	R3: The TOP may not have authority over external registered entities. The TOP should only have to notify and coordinate with those external entities that have the necessary authority.
Response: Requirement R3 deals with operations planning, thus the notification would be to convey information—not an instruction to implement. The hierarchy of authority is known by the Transmission Operator and other registered entities. This is known even if they are members of differing market structures, contract arrangements, or other organizational arrangements; thus the Transmission Operator will know the effective path of communications to use. No change made.		
ISO/RTO Standards Review Committee	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase ‘within its TOP Area or for which it has been notified by another TOP under R3’ in R1 immediately following (IROL).
Pepco Holdings Inc	No	PHI supports the comments provided by the ISO/RTO Standards Review Committee.
ISO New England Inc.	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity.

Organization	Yes or No	Question 2 Comment
		Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Constellation Energy	No	CCG, CECD and CPG concur with ISO/RTO Standards Review Committee Position: Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
BGE	No	BGE concurs with ISO/RTO Standards Review Committee Position: Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Southwest Power Pool Reliability Standards Development Team	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1

Organization	Yes or No	Question 2 Comment
		immediately following (IROL).
Southwest Power Pool, Inc.	Negative	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Nebraska Public Power District	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. We suggest the following language for R1: "Each Transmission Operator shall have an Operational Planning Analysis assessing whether the planned Transmission Operator Area operations for the next day will exceed the area Facility Ratings or Stability Limits during anticipated normal and Contingency (at a minimum N-1 Contingency planning) event conditions." Requiring the TOP to develop a plan to operate within each IROL in R2 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its Transmission Operator Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Response: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to		

Organization	Yes or No	Question 2 Comment
analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies1identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made. Requirement R2 is the correct reference for the second group of comments, not Requirement R1. The SDT believes it is important for the Transmission Operator to develop a plan to operate within each IROL. Further the Reliability Coordinator must inform the Transmission Operator of all IROLs that impact its Transmission Operator Area or that its area can impact in other areas; and other Transmission Operators must inform them of SOLs that either impact its area or that its area may impact. Similar to the often-discussed "loop flow" concern, each entity must recognize that operations within its area may impact SOLs in another area and vice		

Organization	Yes or No	Question 2 Comment
versa.		
United Illuminating Company	No	The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, UI suggests the requirement should either state the requirement for a process to conduct an Operational planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement.R1. The Transmission operator shall CONDUCT an Operational Planning Analysis for the next day's planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. R2: uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-011 R5. SOL's that affect a TOP internal area would also affect the RC area.
Northeast Power Coordinating Council	No	The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, suggest that the requirement should either state the requirement for a process to conduct an Operational Planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement.R1. The Transmission Operator shall CONDUCT an Operational Planning Analysis for the next day’s planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. Requirement R2 uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-014 R5. SOL’s that affect a TOP

Organization	Yes or No	Question 2 Comment
		internal area would also affect the RC area. The Drafting Team needs to define the term "internal area reliability" in order to improve the clarity of the standard (see Question 1 comments regarding TOP-001 Requirement R8). Regarding Requirement R3, would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall?
Response: R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate and, thus, still applies. R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. R3: When providing the notification, no confidential information must be provided, only that the entity has a role to play in an operating plan that the Transmission Operator has developed to address system constraints. No other regulations may be violated in the issuance of the notifications, but the Generator Owner, Generator Operator, or Balancing Authority would know that they would be asked to change something in their generation operations as a part of their role(s).		
Southwest Power Pool Regional Entity	No	See item number 5 for comments.
Response: See the response to Q5.		
Bonneville Power Administration	No	Given the potential uncertainty regarding how many day ahead studies may be required, BPA suggests adding more clarity to the standard TOP-002-3. BPA recognizes that various regions experience peak operations at different times of the day, anticipated generation patterns shift over the course of the day, and

Organization	Yes or No	Question 2 Comment
		transmission facilities come in and out of service for planned work at various times throughout the day. Hence, due to these multiple shifts in forecast system conditions, it is unclear whether more than one study is required to meet the requirements of this standard.
Response: The requirement states “what” must be done, not “how” it is to be done. There are many tools (please note that use of tools is not required) and the various processes and/or tools may differ with a resulting different number of “studies” required. The Operational Planning Analysis is to address “expected system conditions”, such as load forecasts, generator outputs, and system constraints. For those larger, more complex systems, the SDT expects the process may be complex. However, for smaller entities which may have a very constant load characteristic and a very robust transmission system, one analysis may suffice for a very broad range of different “expected system conditions”. No change made.		
Imperial Irrigation District (IID)	No	R1 - This requirement requires the Transmission Operator to have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions (Comment) - Recommendation that the requirement language be changed to “Each TOP shall perform the required Operational Planning Analysis for Next-Day Operations to assess if the Next-Day Operations Plan will exceed any of its Facility and/or stability limits under normal or emergency conditions”. R2 - This requirement requires the Transmission Operator to develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 (Comment) Recommend that the language be revised for clarity to state the following; “The TOP shall develop a plan to operate within established IROL and SOLs according to the Operation Planning Analysis performed for its Next-Day Operation in Requirement 1. R3 - This requirement requires the TOP to notify all NERC registered entities

Organization	Yes or No	Question 2 Comment
		identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) (Comment) - Recommend revising the language in the requirement to state the following; "The TOP shall notify all affected NERC Registered entities of possible impacts identified in its Operational Planning Analysis for its Next-Day Operations in Requirement 1. M2 - The measurement requires the TOP to have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement (Comment) - Revise the Measurement to state the following; "The TOP shall have evidence that it developed a plan to operate within established IROL or SOLs supporting its internal reliability area as a result of its Operational Planning Analysis performed". M3 - Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records. (Comment) - Revise the measurement to sate the following; "The TOP shall provide evidence that it notified affected NERC Registered Entities as being impacted in the Operational Planning Analysis related to its Next-Day plan. Such evidence shall include but not be limited to dated E-Mails, Operator Logs, or Voice Recordings. Data Retention - Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period for analyses, the most recent three months 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. If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer. The Compliance Enforcement Authority shall

Organization	Yes or No	Question 2 Comment
		keep the last audit records and all requested and submitted subsequent audit records. (Comment): The time frames appear to be pretty specific for the data retention. However when will the entity know that it has to save the evidence farther back than the set time frame. Would it not be better to have the Data Retention language require the entity to save all evidence back 12 months and to save any evidence related to a system disturbance/event?
Response: R1: The requirement is to assess the Operational Planning Analysis (OPA). An entity may do this by performing a new OPA each day, or even more often, but it is not required to do so. The SDT can postulate that the varying results of the assessment(s) may indicate the need for a new analysis, or may indicate that the existing analysis is still appropriate. No change made. R2: See above response for R1. No change made. R3: The SDT requirement to notify entities of their role(s) in the operating plans goes beyond just informing them of system impacts. The role(s) will notify the entity that they will have actions to take when the Transmission Operator must implement an operating plan to address system constraint(s). No change made. The SDT made no changes to Measures M2 and M3 because the requirements were not changed. Data Retention: The language indicates that the entity will be asked by its Compliance Enforcement Authority (or directed) to save the evidence father back than the set timeframe. No change made.		
Kansas City Power & Light	No	The words “develop a plan” in R2 are too broad. Recommend the requirement be modified to include, “within its TOP area” as in R1. Also the use of “Contingency event conditions” is not clear in requirement R1. Recommend specifying n-1 as the contingency scope.
Response: The SDT believes it is important for the Transmission Operator to develop a plan to operate within each IROL. Further the Reliability Coordinator must inform the Transmission Operator of all IROLs that impact its Transmission Operator Area or that its area can impact in other areas; and other Transmission Operators must inform them of SOLs that either impact its area or that its area may impact. Similar to the often-discussed “loop flow” concern, each entity must recognize that operations within its area may impact SOLs in another area and vice versa. No change made.		

Organization	Yes or No	Question 2 Comment

The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them.

FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities.

FAC-011, for the operations horizon, requires that the SOLs represent the following:

"R2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system."

TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will

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allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made.		
SERC OC Standards Review Group	No	Why did the Drafting Team use the terms “Facility Ratings” and “Stability Limits” in Requirement 1 rather than SOLs and IROLs as used in subsequent Requirements? We suggest the Drafting Team further clarify or define the term “supporting internal area reliability” as an aid in demonstrating compliance and how this requirement (R2) enhances reliability.
Response: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: “R2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate		

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US Army Corps of Engineers	No	Issue: The SDT uses a non FERC approved term of Operational Planning Analysis, This term is in the NERC Glossary of terms. Recommend that this statement be forwarded with this Standard to FERC for approval. Issue: R2: statement its internal area reliability Should be clarified to state: R2: Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its

Organization	Yes or No	Question 2 Comment
		Transmission Operators area, identified as a result of the Operational Planning Analysis performed in Requirement R1. M2: statement its internal area reliability could be clarified to state: has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis
MRO-NSRF	No	Issue: The SDT uses a non FERC approved term of "Operational Planning Analysis", This term is in the NERC Glossary of terms. Recommend that this statement be forwarded with this Standard to FERC for approval. Issue: R2: statement "...its internal area reliability..." Should be clarified to state: R2: Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis performed in Requirement R1. M2: statement "...its internal area reliability..." could be clarified to state:"...has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis..."
Response: The definition of Operational Planning Analysis was approved by FERC in March 2011. R2: The SDT has revised the language to change "internal area reliability". **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. M2: The SDT revised Measure M2 to correspond to the changes in Requirement R2.		
ACES Power Marketing	No	We largely agree with the changes but have identified the following specific

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Member Standards Collaborators		issues.We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted into the purpose statement. For Requirement R1, it is not clear why focus is on Facility Ratings and Stability Limits rather than SOLs. We suggest using the term SOL instead.
Southwest Transmission Cooperative, Inc.	Affirmative	We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted into the purpose statement. For Requirement R1, it is not clear why focus is on Facility Ratings and Stability Limits rather than SOLs. We suggest using the term SOL instead.

Response: The SDT has been given SDT Guidelines that state that all requirements are written for the BES. No change made.

R1: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by

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the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies1identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made.		

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Georgia System Operations	No	GSOC feels that some clarity should be provided. In R1, the rationale confuses things. It states things that are not in the requirement and goes beyond the requirement. If something is intended by the language of R1 other what is stated, then that intent should be clearer in the requirement. For example if a process is required, then state so in the requiremnt. It should not be in a rationale. Also, the comment in the rationale about being able to complete the analysis even if tools are not available is inappropriate in this standard since the situation is covered in EOP-008-1. Remove the rationale and if needed clarify the requirement. R1 states that the TOP should be allowed to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. It does not state that an assessment of this must be done, only that it be allowed.R2 states that the TOP shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which has been identified by the TOP as supporting its internal area reliability, identified as a result of the OPA performed in Requirement R1. R1 does not require that IROLs and SOLs be identified. What if the TOP does not identify if there are any SOLs as a result of the OPA? There are other examples in these standards in which something in the OPA is referred to but is not required to be in the analysis. Better clarity is needed regarding just what the end results of the analysis must be. R3 requires that entities identified in the plan be notified as to their role. Would this be initially and whenever their role changes thereafter? Or just once? Data Retention: It states that if a TOP is found non-compliant, it shall keep information related to the non-compliance until found compliant. It is inappropriate to use the phrase "found compliant." NERC and the REs do not find entities compliant.

Response: R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate

Organization	Yes or No	Question 2 Comment
and, thus, still applies. No change made. R1: The requirement is for the Transmission Operator to have an Operational Planning Analysis (timeframe of an OPA is built into the definition). If the Transmission Operator chooses to use an existing OPA, then it cannot be confirmed to be appropriate for the next day without performing an assessment of the OPA. If the Transmission Operator chooses to build a new OPA (each day or at a differing recurrent schedule), then the assessment is part of building the OPA in order to make it appropriate to the "expected system conditions". No change made. Identification of SOLs: There is no need to state in these requirements that the IROLs and SOLs be identified, because the Transmission Operator is required to do that by the FAC standards. The end result of an OPA is an evaluation of the "expected system conditions" and the development of operating plans that may be needed to address any identified system constraints. No change made. R3: Entities are to be notified as to their role every time it performs the assessment. Data Retention: The language you question has been provided to the SDT by the NERC Compliance group and is "boiler plate" language that the SDTs are instructed to use. No change made.		
City Water Light and Power (CWLP) - Springfeild - IL	No	R1 should utilize SOL and IROL criteria as opposed to Facility Ratings and Stability Limits criteria for consistency and clarity R1 Rationale language lacks clarity. Poor definition of "process", "tools", and "procedures" could be construed to indicate that a TO must be able to perform analysis internally even when basic non-automated "tools" such as offline power flow software are not available. The intent of "tool" is unclear in general for this instance. If the intent is to capture the use of online automated tools such a Real-Time Contingency Analysis and ensure that offline analysis capabilities are retained, the language should explicitly include "online automated tools" or "real-time automated tools"
Response: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented		

Organization	Yes or No	Question 2 Comment
within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made. R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to		

Organization	Yes or No	Question 2 Comment
assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate and, thus, still applies. No change made.		
We Energies	No	How current should the Operational Planning Analysis be? By definition it can be 12 months ahead. Data Retention: The second paragraph states that Measures must be complied with. Compliance with measures cannot be required.
Response: The Transmission Operator must have an OPA (the timeframe is contained within the definition). Data Retention: You are correct. The SDT has made a conforming change to the language to eliminate the phrase.		
American Transmission Company, LLC	No	Requirement 1 - Granted, if the rationale does not mandate "how" an analysis is completed, a better requirement of the "what" should be stated. If this analysis base-case, N-1, is unilateral by the TOP, without iteration with the BA, then should the process be documented?
Response: R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate and, thus, still applies. No change made. In the development of the planned operations for the next day, the Balancing Authority would supply expected generator outputs to the Transmission Operator. The Transmission Operator would determine whether there are any system constraints that would require changes by the Balancing Authority, such as a re-dispatch or other action that may require alterations to the expected generator outputs to be performed by the Balancing Authority. If such things are identified, the Transmission Operator will notify the entities of their role(s) in the operating plans.		
Consolidated Edison Co. of NY, Inc.	No	Comments: In Requirement R2 the Drafting Team needs to define the term "internal area reliability" in order to improve the clarity of the standard. Regarding Requirement R3: Would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888

Organization	Yes or No	Question 2 Comment
		Firewall? Requirement 3 should be deleted. Market rules may prohibit the TOP from notifying all identified registered entities of their involvement in a given Operational Planning Analysis. This notification function may need to be performed by the RC.
Orange and Rockland Utilities, Inc.	No	Regarding Requirement R3: Would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall? Requirement 3 should be deleted. Market rules may prohibit the TOP from notifying all identified registered entities of their involvement in a given Operational Planning Analysis. This notification function may need to be performed by the RC.
Response: R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. R3: When providing the notification, no confidential information must be provided, only that the entity has a role to play in an operating plan that the Transmission Operator has developed to address system constraints. No other regulations may be violated in the issuance of the notifications, but the Generator Operator, Generator Operator, or Balancing Authority would know that they would be asked to change something in their generation operations as a part of their role(s). The Transmission Operator may direct Balancing Authorities for reliability reasons. Yes, the Reliability Coordinator may also direct the Balancing Authorities, but the Transmission Operator is not precluded from doing so. No change made.		
Manitoba Hydro	No	R1 - Given that an Operational Planning Analysis is itself an assessment of planned operations (i.e. the definition of Operational Planning Analysis is 'An analysis of the expected system conditions for the next day's operation…') it is unnecessary to state that the Operational Planning Analysis must allow an assessment of planned operations. Accordingly, Manitoba Hydro suggests that the phrase that will allow it

Organization	Yes or No	Question 2 Comment
		to assess…' be replaced with "assessing".
Response: The SDT believes your comments represent a question of semantics. The SDT differentiates between an "analysis" and an "assessment". The difference is that the entity assesses the analysis it has performed to determine that the OPA is still representative of "expected system conditions". That is "what" must be done. The "how" is left up to the entity. The SDT can postulate that the entity may perform a new OPA and, in the process, assess that it is representative of "expected system conditions", or that it may take an existing OPA and assess it to determine that it still is representative. No change made.		
ReliabilityFirst	No	ReliabilityFirst has the following comments for consideration:1. R1 - ReliabilityFirst recommends removing the rationale box from the standard. ReliabilityFirst believes this is not really the rationale for the requirement but rather explains how to measure (show evidence) for the requirement.2. R2 - ReliabilityFirst recommends deleting the following words from the requirement, "which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1". ReliabilityFirst believes this language does not add anything to the requirement. 3. R2 and R3 - R3 requires the Transmission Operator to notify all NERC registered entities identified in the plan(s) but there is no corresponding requirement for the Transmission Operator to identify NERC registered entities in their plans. ReliabilityFirst recommends incorporating this concept into R2. 4. Data retention - ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example, the last sentence states "the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>paragraphs in the Data Retention section.</td></tr>
<tr><td colspan="3"> Response: R1 rationale box: The SDT agrees and has eliminated the rationale box.
R2: A Transmission Operator may identify certain SOLs as important, although they don’t rise to the level of an IROL, but support reliability internal to the Transmission Operator Area. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. However, the SDT has clarified the wording in Requirement R2 due to comments received.
R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting <s>its internal area </s>reliability<u> internal to its Transmission Operator Area</u>, identified as a result of the Operational Planning Analysis performed in Requirement R1.
The SDT believes that to notify the entities, the Transmission Operator must somehow know who the entities are and that stating a requirement to identify them before notifying them would be redundant and would not add to reliability. No change made.
Data Retention: The entity is to do all the shorter retention requirements first and go to the longer retention only if the CEA asks them to do so. No change made. </td></tr>
<tr><td>Duke Energy</td><td>No</td><td> o R2 - Consistent with our comment above on TOP-001-2 Requirement R8, the phrase “supporting its internal area reliability” should be further clarified in some way. o M2 typo - the word “plan” has an extra “n”. </td></tr>
<tr><td colspan="3"> Response: R2: The SDT has revised the language.
R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting <s>its internal area </s>reliability<u> internal to its Transmission Operator Area</u>, identified as a result of the Operational Planning Analysis performed in Requirement R1.
M2: The typo has been corrected. Please note that the typo is not seen in the “clean” copy. </td></tr>
</table>

Organization	Yes or No	Question 2 Comment
South Carolina Electric and Gas	No	Please provide clarity on the phrase "support its internal area reliability" in R2.
Response: R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Oklahoma Gas and Electric	No	Regarding R2, please consider additional clarifying language that each TOP need only develop a plan to operate within IROL and SOL that is applicable to them. Also, clarify what "internal area realibility" means - is this the same as Transmission Operator Area discussed in R1?
Response: The SDT believes it is important for the Transmission Operator to develop a plan to operate within each IROL. Further the Reliability Coordinator must inform the Transmission Operator of all IROLs that impact its Transmission Operator Area or that its area can impact in other areas; and other Transmission Operators must inform them of SOLs that either impact its area or that its area may impact. Similar to the often-discussed “loop flow” concern, each entity must recognize that operations within its area may impact SOLs in another area and vice versa. No change made. R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Westar Energy	No	The stated rationale for R1 raises more concerns than the actual language in R1. How can an entity complete an analysis by procedure? The rationale seems to indicate that an Operational Planning Analysis is possible

Organization	Yes or No	Question 2 Comment
		without tools, please explain. Are anticipated contingency event conditions intended to be N-1 from the planned system configuration?

Response: R1 rationale box: The SDT agrees and has eliminated the rationale box.

The requirement states "what" must be done, not "how" it is to be done. There are many tools (please note that use of tools is not required) and the various processes and/or tools may differ with a resulting different number of "studies" required. The Operational Planning Analysis is to address "expected system conditions", such as load forecasts, generator outputs, and system constraints. For those larger, more complex systems, the SDT expects the process may be complex. However, for smaller entities which may have a very constant load characteristic and a very robust transmission system, one analysis may suffice for a very broad range of different "expected system conditions".

The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them.

FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities.

Organization	Yes or No	Question 2 Comment
FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies1identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made.		
Ameren	No	R1. The current language invites a retrospective assessment and a potential compliance issue that if a bad event occurs that was not in the forecast, it may call into question whether the TOP adequately "allowed it to assess" whether operations where within limits. We recommend SDT re-write the requirement: "Each TOP shall have an Operational Planning Analysis that represents projected System conditions for the next day, within its Transmission Operator Area, to identify any projected exceedance of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions." R2. Although the time-horizon assignment provides some cover for real-time SOLs, it would be preferable to add direct clarification to the Requirement as follows. "Each TOP shall develop a next day plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) ..." R3. Taken literally, this Requirement could require TOP notification to a GOP/PSE/LSE that they will be dispatched down in real-time for a projected congestion issue (SOL).

Organization	Yes or No	Question 2 Comment
		This does not make sense and certainly not in organized LMP markets where they would have advance knowledge of market conditions AND FOR THINGS THAT ARE ROUTINE. This is the nexus of the problem for us with this Requirement. The need to notify others of their roles should be restricted to unusual actions in the case of SOL resolution. Arguably this could be true for IROLs too but given the impact perhaps it could remain. We suggest that the Requirement say, "Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) when those actions are unusual or abnormal actions." OR"Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) for the resolution of IROLs or when those actions are unusual or abnormal actions for the resolution of SOLs."
Response: The SDT believes the existing language of draft Requirement R1 says what you are requesting. No change made. R2: The FAC standards provide clarity as to the development of Facility Ratings and SOLs. IROLs are a sub-set of SOLs. To provide differing language here would be to provide potential conflict and confusion. No change made. R3: Requirement R3 deals with operations planning; thus the notification would be to convey information—not an instruction to implement. The hierarchy of authority is known by the Transmission Operator and other registered entities. This is known even if they are members of differing market structures, contract arrangements, or other organizational arrangements; thus the Transmission Operator will know the effective path of communications to use.		
Roger C Zaklukiewicz		Requirement R1 needs to be modified as the following terms in 1.1 are problematic to compliance and enforcement. Remove the term "but not limited to". Why must the data to be exchanged include that on all facilities that operate at levels lower than the Bulk Electric System to ensure the reliability of the interconnected BES - especially if the BES is to be recognized as the "bright line" transmission system that operates at 100 kV or above.
Response: The SDT believes you intended these comments for TOP-003, Requirement R1. Please see the responses to TOP-003 comments.		

Organization	Yes or No	Question 2 Comment
California ISO	Affirmative	The ISO supports the changes made in TOP-002-3 but notes that the “Seasonal Assessment” previously required by TOP-002-2 is no longer addressed in the TOP-002-3 wording. Is this an oversight or is this seasonal assessment going to be contained elsewhere?
Response: The SDT places reliability emphasis upon a daily assessment for the next day (hence the Operational Planning Analysis). The entity could have a library of various OPAs from which to select an appropriate one for assessment, or could develop an OPA each day (or even more often), but is not required to do so.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	The term “anticipated ... Contingency event conditions” in R1 is not a NERC defined term and could be interpreted as requiring analysis of all contingencies including extreme events. The requirement should clarify if it only applies to certain types such as category P1 or whether each TO can independently select which types of contingencies they anticipate. One suggested form or rewording the requirement could be: R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal conditions and TPL-001-2 category P1 Single contingencies.
Response: The Operational Planning Analysis (OPA) is a defined term and includes “expected system conditions” for the next day. The Contingencies which would apply are presented in the TPL standards. The Transmission Operator must address, at a minimum, the Contingencies presented, but may address more than what is required. Further, Facility Ratings and Stability Limits are defined terms and the FAC standards present the level of Contingencies that must be addressed in the Facility Ratings and SOLs methodologies. To specify only the proposed P1 single Contingencies may be too limiting. No change made.		
Tennessee Valley Authority	Affirmative	Further clarification is needed on the phrase - "internal area reliability".
Progress Energy	Yes	A definition of "internal area reliability" is needed

Organization	Yes or No	Question 2 Comment
Response: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Associated Electric Cooperative, Inc.	Yes	R1 Rationale Change: Rework or remove entirely Rationale: The R1 Rationale section does not match the R1 requirement as currently worded, and frankly is impossible, within the timing constraints of next-day analysis. (Example: PSS/E is technically a tool for steady-state network analysis. Without that tool, or a similar network-analysis tool being available, such analysis would be impossible by hand.) R3 Requirement wording Change: “in the plan(s)” To: “in the N-1 contingency-related plan(s)”Then Append: “, N-2 related contingency-plan(s) should be omitted unless highly plausible.” Rationale: This recommended change seeks to avoid information overload on neighbors, while still encouraging more in-depth near-term contingency planning.
Response: R1 rationale box: The SDT has eliminated the rationale box. Requirement R3 deals with operations planning; thus the notification would be to convey information—not an instruction to implement. The hierarchy of authority is known by the Transmission Operator and other registered entities. This is known even if they are members of differing market structures, contract arrangements, or other organizational arrangements; thus the Transmission Operator will know the effective path of communications to use. The plans are limited to those developed in Requirement R2. No change made.		
Independent Electricity System Operator	Yes	We assess that the industry’s comment on R3 regarding the need to inform all NERC registered entities identified in the plan(s) was due to the absence of a requirement to identify these entities. We therefore suggest to revise Requirement R2 to drive home the need to identify registered entities that are included in the plan(s) to operate to within IROL and SOL, and set the stage for R3:Each Transmission Operator

Organization	Yes or No	Question 2 Comment
		shall develop a plan, and identify the entities that will be required to implement actions, to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
Response: The SDT believes the current wording of Requirement R3 is sufficient. No change made.		
American Electric Power	Yes	R2: Once again, it needs to be clarified whether this requirement is in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumes this is based on Real Time Flow, however we encourage the drafting team to provide clarifying language to make it more clear to the reader.
Response: TOP-002-3 is about Operations Planning, thus it cannot be addressing actual Real-time flow. It addresses those flows contained in the Operational Planning Analysis (OPA) and the assessment thereof. Based upon that assessment and the OPA, the Transmission Operator will develop a plan to operate. No change made.		
NIPSCO	Yes	None at this time
Dairyland Power Cooperative	Yes	
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	
Omaha Publc Power District	Yes	
Texas Reliability Entity	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 2 Comment
US Bureau of Reclamation	Yes	
Xcel Energy	Yes	
FirstEnergy	Yes	
Dominion	Yes	
PacifiCorp	Yes	
Lincoln Electric System (LES)	Yes	
LG&E and KU Serivces	Yes	
Western Area Power Administration	Yes	
FMPP	Yes	
Luminant Energy Company, LLC	Yes	
Response: Thank you for your support.		

3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: There were a number of requests for clarification which the SDT have addressed either through changes to the language of the requirements or through specific responses to those comments. There was one substantive change to the standard – the addition of the Distribution Provider to the list of applicable entities in general and to Requirement R5 specifically.

The SDT changed the effective date for all requirements in proposed TOP-001-2, TOP-002-3, and TOP-003-2 to 12 months in response to comments except for proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.

The following changes have been made due to industry comments:

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. The specification shall include:

R3. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.

R4. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification as developed in Requirement R1to entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R2. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ 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 as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R~~2~~3 or R~~3~~4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R~~4~~5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

Data Retention 4. Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~and operating analysis assessment processes and tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R4 and Measurement M4.

Organization	Yes or No	Question 3 Comment
Luminant Energy	Abstain	TOP-003-2 as currently written does not provide any recourse for the entity receiving a data request if that entity feels the data request is unreasonable either in content or timing or if the entity does not have the data available to submit. As such I would recommend modify R5 as follows: R5. Each......shall satisfy the obligations of the documented specification for data. R5.1. If the entity receiving the data request cannot provide the requested data either in content or timing then the entity receiving the data request shall notify the requesting entity and provide a reason for not providing the data.
Kansas City Power & Light	No	These requirements do not recognize the limitations of data exchange capability with an entity and the sources of data an entity has. Recommend these requirements be modified to include "within the data exchange capabilities and data available of the recipient of the data specification".
City Water Light and Power (CWLP) - Springfeild - IL	No	R1 and R2 require specifications for data exchange which do not account for the ability of the respondent to meet the specification. As written, the requirement could force a respondent to continue to provide data with such a format, periodicity,

Organization	Yes or No	Question 3 Comment
		or deadline that would be an undue burden to the respondent. All requirements should explicitly stress a mutually agreed plan and R1.1/R2.1 should refer to classes or types of as a qualifier. Likewise, R5 should explicitly state that respondents shall satisfy the obligations within the context of a mutually agreed specification.
Dairyland Power Cooperative	No	R1 and R2 refer to "A periodicity for providing data" and "The deadline by which the respondent is to provide the indicated data". What if this specification is unreasonable? To address this concern, DPC suggests adding the words "mutually agreeable" as was used in reference to the format specification.
Response: Requirement R1 should prevent a Transmission Operator from requesting data that another entity can't provide. There are arbitration processes available to straighten these matters out if all else fails. No change made.		
Muscatine Power & Water, MidAmerican Energy Co.	Negative	There is a great possibility of double jeopardy when R3 and R4 have in part the statement of "...in meeting its NERC-mandatory reliability requirements." So, an Entity could be found non-compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown "...in meeting its NERC-mandatory reliability requirements," then they would be found non-compliant with this Standard. It is not clear why this Standard is being written with the statement of "...in meeting its NERC-mandatory reliability requirements."
US Army Corp of Engineers	No	Issue: There is a great possibility of double jeopardy when R3 and R4 have in part the statement of in meeting its NERC-mandatory reliability requirements. So, an Entity could be found non compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown in meeting its NERC-mandatory reliability requirements then they would be found non compliant with this Standard. It is not clear why this Standard is being written with the statement of: in meeting its NERC-mandatory reliability requirements. As stated in the NERC Standard Process Manual, under Background, NERC works with all stakeholder segments of the electric industry, including electricity users, to develop standards for the reliability planning and

Organization	Yes or No	Question 3 Comment
		reliable operation of the bulk power systems. Recommend that in meeting its NERC-mandatory reliability requirements, be deleted and replaced with reliable operation as defined as operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance. Or, please review IRO-010-1a, requirement 1 and use like terminology for this Standard.
Lincoln Electric System (LES)	No	Please refer to comments submitted by MRO's NERC Standards Review Forum for LES' concerns related to TOP-003.
MRO-NSRF	No	Issue: There is a great possibility of "double jeopardy" when R3 and R4 have in part the statement of "...in meeting its NERC-mandatory reliability requirements." So, an Entity could be found non compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown "...in meeting its NERC-mandatory reliability requirements" then they would be found non compliant with this Standard. It is not clear why this Standard is being written with the statement of: "...in meeting its NERC-mandatory reliability requirements". As stated in the NERC Standard Process Manual, under Background, "NERC works with all stakeholder segments of the electric industry, including electricity users, to develop standards for the reliability planning and reliable operation of the bulk power systems. Recommend that "...in meeting its NERC-mandatory reliability requirements", be deleted and replaced with "reliable operation" as defined as "...operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance...". Or, please review IRO-010-1a, requirement 1 and use like terminology for this Standard.
Response: The SDT views the requirements as two separate and distinct actions. In Requirements R1 and R2, the entity is developing the specification and in Requirements R3 and R4 the entity is distributing the specification. Therefore, there is no double jeopardy.		

Organization	Yes or No	Question 3 Comment
No change made. This standard exactly matches IRO-010-1a in content and intent. No change made.		
Volkmann Consulting, Inc.	Negative	TOP-003-2 R5 does not adequately replace PRC-001 R2. TOP-003-2 R5 does not require notifying the RC and drops the requirement of GOP to analyze equipment and relay failures, TOP-003-2 R5 states GOP obligations as specified in R3 and R4, however R3 and R4 are not applicable to GOP.
Response: There is nothing in PRC-001-1, Requirement R2 about analysis. The SDT believes you are thinking of PRC-004-2a, Requirement R2 which is not part of this project and is not intended to be replaced by the revised standards. No change made.		
Northeast Power Coordinating Council	No	TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates the TO, LSE, and Generator Owners to provide this real-time data. These entities provide a wealth of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It is not clear that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.TOP-003 R5 has only a severe VSL. Data providers can provide hundreds if not thousands of points to TOPs. If one RTU goes down is the data provider going to be assessed a severe VSL? TOP-003-2 R1.1 states: R1. Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: Long term outages of Bulk Electric System (BES) Facilities. Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES NPCC believes language such as but not limited to and levels lower than the BES to be problematic and beyond the scope of what is needed in the standard and also creates potential for compliance issues.
United Illuminating Company	No	TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates TO, LSE, and Generator Owners to provide this real-time data. These entities provide a multitude of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It

Organization	Yes or No	Question 3 Comment
		is not clear to UI that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.
Response: It is not the intent of the SDT that TOP-003-2 penalizes entities for communication errors. The intent is to have the data communications established. Communication errors are handled in the COM standards. No change made.		
Dominion	No	If this question was meant to refer to TOP-003-2, then Dominion offers the following comments: M5 reads "Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities." Since R2 was added, Dominion suggest M5 should read as "receiving a data specification in Requirement R3 or R4 shall make available evidence that is has satisfied the obligations of the documented specifications for data in accordance with Requirement R5....".
Response: The SDT agrees and has changed measure M5 accordingly. **M5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R~~2~~3 or R~~3~~4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R~~4~~5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.		
SERC OC Standards Review Group	No	There appears to be ambiguity for R1 and R2 - is the VSL applicable to the TOP/BA requesting the data or is it applicable to the TOP/BA providing the data? If it applies to the TOP/BA requesting the data we would suggest that the SDT be consistent with

Organization	Yes or No	Question 3 Comment
		the VSLs in IRO-10-1a.
Response: The SDT does not see the confusion pertaining to Balancing Authority/Transmission Operator that the VSLs in Requirements R1 and R2 apply. The requirement is for the Transmission Operator/Balancing Authority to document a specification, it would have to be the Transmission Operator/Balancing Authority writing the specification and ultimately requesting the data through Requirements R3 and R4. No change made.		
Constellation Energy	No	The Drafting Team may want to consider addressing a time period for responding to a data request to ensure parties are given time to respond. For example, a BAs data request may be driven by the TOP's data request. If a BA receives a data request for information from the TOP that sources from a GOP, the BA will need to establish a data request from the GOP that has the same deadline. If the GOP is unable to supply the data they may be non-compliant if they do not meet the deadline.
Response: Parts 1.4 and 2.4 discusses a deadline for responding to the data request. No change made.		
ACES Power Marketing Member Standards Collaborators	No	We largely agree with the changes but have identified the following specific issues.We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Because of the difficulties experienced by some entities in receiving the RC data specification in IRO-010-1a, we recommend that the implementation of TOP-003-2 Requirement R5 occur a couple of months after the implementation in TOP-003-2 Requirements R1-R4. IRO-010-1a is a parallel standard to TOP-003-2 and the effective date of the distribution of the RC data specification was simultaneous to

Organization	Yes or No	Question 3 Comment
		the effective date of the requirement for the recipients to comply with the data specification. This meant that the RC could provide the data specification on the same date that the recipients had to meet the data specification. Unfortunately, there were some entities expecting to receive the data specification that did not and were concerned about a potential non-compliance. What if an auditor determined the RC should have provided the data specification? Would the entity that expected to receive the data specification be held responsible? By staggering the effective date of Requirement R5, this confusion can be avoided.
Southwest Transmission Cooperative, Inc.	Affirmative	We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Because of the difficulties experienced by some entities in receiving the RC data specification in IRO-010-1a, we recommend that the implementation of TOP-003-2 Requirement R5 occur a couple of months after the implementation in TOP-003-2 Requirements R1-R4. IRO-010-1a is a parallel standard to TOP-003-2 and the effective date of the distribution of the RC data specification was simultaneous to the effective date of the requirement for the recipients to comply with the data specification. This meant that the RC could provide the data specification on the same date that the recipients had to meet the data specification. Unfortunately, there were some entities expecting to receive the data specification that did not and were concerned about a potential non-compliance. What if an auditor determined the RC should have provided the data specification? Would the entity that expected to receive the data specification be held responsible? By staggering the effective

Organization	Yes or No	Question 3 Comment
		date of Requirement R5, this confusion can be avoided.
Response: The purpose of the standard is to address reliability needs. Any concerns about BES vs. BPS in standards are better directed toward the NERC Standards Committee. No change made. The SDT has changed the effective date for the implementation of this project to 12 months except for proposed TOP-003-2, Requirements R1 and R2 which will be in 10 months.		
LG&E and KU Serivces	No	LG&E and KU Services do not believe that data/evidence retention requirements should be modified by the Compliance Enforcement Authority. This potentially will result in different data retention requirements across regions. A Compliance Enforcement Authority should enforce only what is written within the standard and not have the option of expanding the requirement. 4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.
Response: The SDT is using standard boilerplate language in the Data Retention section. It is not within the scope of the SDT to alter such language. Questions about such situations should be taken to the NERC Standards Committee. No change made.		
Georgia System Operations	No	R5 is too unilateral. A TOP could send a spec to an entity for some data that the entity is not able to provide and per this requirement the entity will still be required to provide it. There must be some mutual agreement to more than just the format. There must be agreement to what can be provided and that the data is needed by the TOP's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements. Also some provision must be allowed to cover when data or the transfer method is unavailable (e.g., when an RTU goes down). A similar situation applies to BAs sending a spec to an entity.
Response: Requirement R1 should prevent a Transmission Operator from requesting data that another entity can't provide. If all else		

Organization	Yes or No	Question 3 Comment
fails, there are arbitration processes to clear up such matters. No change made.		
Western Area Power Administration	No	Data an entity specifies in requirement documents need to have some kind of reasonability limit or explanation as to what the data will be used for. As written a TOP or BA can request anything they want and other entities will be required to provide that data, even if the requested data is not available as requested. An entity can also request data not pertinent to the reliability of their system and other entities will still be required to provide it. An entity required to provide the data should have an opportunity to challenge the need for data requested. At least one BA in WECC is running a market and data provided will be used in their market, not for reliability.
Response: Requirement R1 clearly states that the data requested must be for use in an entities Real-time monitoring function or for its Operational Planning Analysis. This restricts the data to reliability oriented data. No change made.		
We Energies	No	R1.4 and R2.4: The deadline must allow time to gather and send the data. If the TOP said immediately, you would be immediately non-compliant. In addition, R2 should include data necessary to perform at least Next Day analysis, even Operational planning Analysis. R5 needs to include the DP. Data Retention: Each bullet states that monitoring is required in accordance with Measures. Measures cannot be requirements.
Response: The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. There are arbitration processes available if all else fails. No change made. Balancing Authorities do not perform Operational Planning Analyses as this is a transmission-oriented task. However, the SDT has inserted a phrase to cover analyses. **R2**. Each Balancing Authority shall create a documented specification for the data necessary for it to perform <u>analysis functions and</u> its required Real-time monitoring. The specification shall include:		

Organization	Yes or No	Question 3 Comment
The SDT agrees. **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. The inclusion of requirements and measures in data retention is standard language and simply ties the data retention language to the requirements and measures together. It does not imply that the measures are requirements. No change made.		
American Transmission Company, LLC	No	In the introduction to this question, the Standard number should be corrected to TOP-003-2. Requirement 1- A data specification must have bounds. There is nothing that would preclude a request for data that is not achievable yet is mandated to be satisfied by Requirement 5. Requirement 1, sub-Requirement 1.2 may never be arrived at given the former.
Response: The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. There are arbitration processes available to straighten these matters out if all else fails. No change made.		
Omaha Publc Power District	No	OPPD is requesting clarification on operational data requirements (R1 and R3) related to "documented specification for the data necessary for it to perform..." What the document should include that is specifying operational data request from or to other Transmission Operators. Additionally, how often operational data specification document should be provided/updated to or from other Transmission Operators.
Response: The SDT believes it is clear as to what is required – the data needed to perform the entities Real-time monitoring and Operational Planning Analyses. No change made. Requirement R1, Part 1.3 covers the periodicity issue. No change made.		
Manitoba Hydro	No	M1 – This measure goes beyond the requirements of the standard, as there is no

Organization	Yes or No	Question 3 Comment
		requirement for a specification document to be dated. Manitoba Hydro suggests either striking 'dated' from M1 or adding the requirement to have a 'dated documented specification' to R1. M2 – Same comment as M1. Manitoba Hydro suggests either striking 'dated' from M2 or adding the requirement to have a 'dated documented specification' to R2. A R3 - For consistency with R1 and overall clarity, Manitoba Hydro suggests changing the wording of R3 to 'Each Transmission Operator shall distribute its documented specification developed in accordance with R1 to those entities that have data required by the Transmission Operator to support its Operational Planning Analysis and Real-time monitoring '. The VSL for R3 should be changed accordingly as well. R4 - For consistency with R2 and overall clarity, Manitoba Hydro suggests changing the wording of R4 to 'Each Balancing Authority shall distribute its documented specification developed in accordance with R2 to those entities that have data required by the Balancing Authority to perform its Real-time monitoring'. The VSL for R4 should be changed accordingly as well.
Response: M1/M2: The requirements refer to deadlines which imply a timing element so it is permissible to add 'dated' to the measures as adherence to a deadline doesn't make much sense otherwise. No change made. R3/4: The SDT does not feel the suggested change adds further clarification. No change made.		
E.ON Climate & Renewables	No	ECRNA appreciates the efforts of the drafting team in eliminating duplicative requirements and efforts, as this is an important part of developing clear and concise standards. However, we are concerned about the end result of an unbounded data specification. Although requirements R1 through R4 are directed toward the Balancing Authority and Transmission Operator, these requirements have a direct impact on the other applicable entities. The lack of guidance to and expectations of the data and format could and most likely will lead to a wide range of data specifications from the multitude of Balancing Authorities and Transmission

Organization	Yes or No	Question 3 Comment
		Operators in North America. Entities that own or operate facilities in multiple regions and work with many BAs and TOPs may have difficulty responding to each individual specification's needs, including timeframe, and format. Also considering the unknowns in the data specifications, the high severity factor on R5 seems unreasonable. In addition, the sub-requirements to R1 and R2 could be written more clearly to identify who the TOPs and BAs are expected to mutually agree with and request information from. One can assume the applicable entities listed in the standard, but explicitly stating this within the standard is a better method and ensures entities are provided an opportunity to provide input in the data specification format.
Response: The data specification concept provides entities with flexibility in crafting the specifications to the exact data that it needs to perform its tasks. Data specifications may be different for the same type of entity within a Transmission Operator Area let alone in different regions of the country. Guidance is provided within the requirement on format, etc. No change made. The severity factor on Requirement R5 is based on its level of importance and its relationship to a similar requirement in IRO-010-1a which has been approved by FERC. No change made. The SDT sees no reliability value in duplicating a list within the bounds of the requirement itself. No change made.		
Texas Reliability Entity	No	Regarding R1, we are concerned that the proposed requirement gives each TOP too much latitude to determine what data it considers necessary. This may cause confusion due to significant differences in data specified by different TOPs and the ability of TOPs to unilaterally change their data specifications. We would prefer that the standard include a basic list of data to be included in the specification. The reference to "mutually agreeable format" in R1 part 1.2 is problematic because it allows the respondents to interfere in the TOP's data collection process. The TOP should be allowed to dictate a reasonable format for data submission. In R2, we are opposed the removal of "Operational Planning Analyses" (OPA) for a Balancing Authority in this requirement, because the BA is "the responsible entity that

Organization	Yes or No	Question 3 Comment
		integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time." A BA should create a documented specification for the data necessary for it to perform an OPA just as a TOP does. The reference to "mutually agreeable format" in R2 part 2.2 is problematic because it allows the respondents to interfere in the BA's data collection process. The BA should be allowed to dictate a reasonable format for data submission. In R3 we suggest changing "operating analysis" to "Operational Planning Analysis," which is a more precise term for what appears to be intended. The same change should be made in Measure M3. In R4 we suggest adding "Operational Planning Analysis," to be consistent with our comment that R2 should require "Operational Planning Analysis" data in the BA's data specification. In the Measures, please check and correct the references to Requirement numbers - some references are to the wrong requirements. Under Data Retention, in the 4th bullet starting with "Each Balancing Authority...", the phrase "and operating analysis assessment processes and" should be struck because it does not align with requirement R4 as currently written. However, we support adding "Operating Planning Analysis" in R4, and this data retention reference should be consistent with the requirement.
Response: The requirement is designed to give the Transmission Operator the flexibility it needs to get the data it requires. It is bound by the provision for data needed to support its Real-time monitoring and Operational Planning Analyses. It is absolutely true that different Transmission Operators may be specifying different data due to their differing operational requirements. Supplying a basic list of data does not provide this flexibility and does not ensure that all data needed would be in the list. No change made. It is unreasonable to allow a Transmission Operator or any other entity to arbitrarily introduce a format that other entities can't support. There has to be some degree of mutual agreement to decisions of this type in order to be fair to all parties involved. The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of		

Organization	Yes or No	Question 3 Comment
reliability. There are arbitration processes available to straighten these matters out if all else fails. No change made. A Balancing Authority can't perform an Operational Planning Analysis by definition since this defined term only applies to transmission-oriented analysis. However, the SDT has added wording to cover analyses. **R2**. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. The specification shall include: R3 – The SDT agrees and has made the language consistent. R3. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. The SDT has changed Requirement R4 to be consistent with the revised Requirement R2. **R4**. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. The references in the Measures have been corrected. The SDT agrees and has made the suggested change consistent with the responses concerning requirement R2 above. **Data Retention 4**. Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~and operating analysis assessment processes and tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R4 and Measurement M4.		
Indiana Municipal Power Agency	No	IMPA believes that the entities (Transmission Operator and Balancing Authority) should be required to create a documented specification that lists exactly what the entities (in R5) need to provide to them to meet the requirement and not be allowed to say that "it is in our manuals and/or agreements." When the Transmission Operator and/or Balancing Authority only references their manuals, it is up to the entity (in R5) to read the manuals that are referenced and then try to come up with a documented specification listing on their own which may or may not include

Organization	Yes or No	Question 3 Comment
		everything that is required by the TO or BA which makes the current draft standard's language very ambiguous. IMPA is not objecting to these entities using manuals as long as a specific documented specification is created and distributed that does more than just list the name of manuals. The documented specifications need to be detailed in what is required from entities to aid in preventing possible non-compliance issues due to an entity missing an item in a manual or including unnecessary items due to being left to their own interpretations.
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by Indiana Municipal Power Agency concerning the need for clearer communication of data specifications in R3 and R4 in order to facilitate compliance with R5.
Response: The intent of Requirements R1 and R2 is for the entity's to do exactly what is cited in your comment. The entity must spell out each piece of data it requires and specify it to the affected entity who will be supplying the data. No change made.		
US Bureau of Reclamation	No	The language change in R1 has not been incorporated into the sub requirements. The requirement R1 was modified to eliminate the second party. A mutual agreement is required in R 1.2 but only party is listed in R1. The language should specify that the TOP is to coordinate its data requests with the appropriate entities and seek mutal agreement on the format.
Response: The SDT believes it is clear who must agree to the format and sees no additional clarity being provided by listing the entities in the text of the requirement. No change made.		
Xcel Energy	No	Applicability - why are Distribution Providers not subject to this standard? Is it possible that a TOP or BA may need information form a DP to perform an "OPA"? "Mutually agreeable" in 1.2 should be removed. The TOP and BA should work with the subject entities, however stating that something must be mutually agreed upon could create delivery and acceptance of data in a less than desired form solely to meet the words of the requirement.

Organization	Yes or No	Question 3 Comment
Response: The SDT agrees and has added the Distribution Provider to the applicable entities and to Requirement R5. **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. There are arbitration processes available to straighten these matters out if all else fails. No change made.		
ReliabilityFirst	No	ReliabilityFirst has the following comments for consideration:1. R1 and R2 - ReliabilityFirst recommends changing the phrase “shall create...” to “shall have...” in R1 and R2. 2. R1 and R2 - ReliabilityFirst recommends changing Part 1.2 and Part 2.2 to state “A format”. ReliabilityFirst believes it may be difficult to audit and enforce the phrase “mutually agreeable”. 3. R3 - ReliabilityFirst seeks clarification on the term “operating analysis assessment” used in R3. Is this language referring to the Transmission Operators Operational Planning Analyses as required in R1? If not, can the SDT clarify what the phase “operating analysis assessment” is referring to? 4. R3 and R4 - ReliabilityFirst seeks clarity on what the phrase “NERC-mandated reliability requirements” is referring to? Is it referring to FERC approved NERC standard requirements or does it encompass NERC Directives, CANs, NERC bulletins, etc. as well? 5. R3 and R4 - R3 references “those entities” and R4 just references “entities”. ReliabilityFirst recommends modifying either R3 or R4 to use consistent language. 6. Data retention - ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example the last sentence states “the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full

Organization	Yes or No	Question 3 Comment
		time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.
Response: The SDT does not believe that the suggested change provides any additional clarity. No change made. The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. The suggested change does not clarify the situation further than what is already written. There are arbitration processes available to straighten these matters out if all else fails. No change made. The SDT has changed requirement R3 for clarity. R3. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. The phrase is in reference to approved Reliability Standards. The SDT agrees and has changed Requirement R3 accordingly. The SDT is utilizing NERC supplied boilerplate language in the Data Retention section. It is out of the scope of this project to make changes to that language. No change made.		
Nebraska Public Power District	No	Comments: Requirements R1 & R2 do not put any meaningful bounds on the data that a TOP or BA may request in the name of monitoring real-time operations. There is no check or balance on spcifying timeframes when the data is required either. Attachment 1 TOP-005-1 contained the type of data that may be required and as such provided a fremework for what type of data was required for real-time monitoring of the Bulk Electric System. As written, it would be possible for a BA or TOP to request data that a registered entity does not have available and require it in an unrealistic timeframe. This puts those entities in a position where they cannot comply with the standard, even though the data requested may not be important in

Organization	Yes or No	Question 3 Comment
		the monitoring of the Bulk Electric System. There need to be reasonable limits on the information requested and how quickly new information may be required from other registered entities.
Response: Requirements R1 and R2 are bound by the language restricting the specifications to Real-time monitoring or Operational Planning Analysis. This restricts the data requested to be only for reliability-related purposes. No change made.		
Ameren	No	R1. Each TOP shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: 1.2. What is meant by mutually agreeable is not clear it implies more than one party, yet this Requirement only applies to one party the TOP. This is illogical and needs to be clarified or removed. 1.4. Strike the deadline and consider using time frame or duration by which the respondent is to provide the indicated data. R2. Each BA shall create a documented specification for the data necessary for it to perform its required Real-time monitoring. The specification shall include: 2.2. What is meant by mutually agreeable is not clear it implies more than one party, yet this Requirement only applies to one party the BA. This is illogical and needs to be clarified or removed. 2.4. Strike the deadline and consider using time frame or duration by which the respondent is to provide the indicated data. R3. After the first instance of specification; state from which requirement; if you were intending R1, then for clarity insert “from R1” There is potentially another compliance issue present; what is meant by NERC-mandated reliability requirements is not clear nor does not match the wording in R1. If the meaning/intent is that NERC-mandated reliability requirements is in fact Operational Planning Analysis and Real-time monitoring, then use those words. If the SDT has other things that the data specification is to be distributed for, then they

Organization	Yes or No	Question 3 Comment
		should be spelled out explicitly here and likely in R1 as well. R4. After the first instance of specification; state from which requirement; if you were intending R1, then for clarity insert “from R1” There is potentially another compliance issue present; what is meant by NERC-mandated reliability requirements is not clear nor does not match the wording in R1. If the meaning/intent is that NERC-mandated reliability requirements is in fact Operational Planning Analysis and Real-time monitoring, then use those words. If the SDT has other things that the data specification is to be distributed for, then they should be spelled out explicitly here and likely in R1 as well. R5. We recommend re-writing: “Each TOP, BA, GO, GOP, IA, LSE, and TO receiving a data specification in Requirement R3 or R4 shall provide the data associated with said data specification. “

Response: R1.2/R2.2**:** The SDT believes that the context is clear and that duplicating a list of entities in the language of the requirement does not provide any additional clarity. No change made.

R1.4/R2.4:The SDT believes that there is no additional clarity provided in the suggested language. No change made.

R3/R4: The SDT does not see any additional clarity provided by the suggestion. No change made.

R3/R4: The term refers to the approved reliability standards. No change made. The SDT has changed the requirements for consistency of wording.

> **R3**. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator’s ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.
>
> **R4**. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority’s analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.

R5: The SDT sees no additional clarity being provided by the suggested change. No change made.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>GTC</td><td>No</td><td>M4 is misreferencing R2 and R4 and should be corrected as follows: ....”receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R5.”</td></tr>
<tr><td colspan="3">Response: The SDT believes that you meant Measure M5. The references have been corrected.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, <s>and </s>Transmission Owner, and Distribution Provider receiving a data specification in Requirement R<s>2</s>3 or R<s>3</s>4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R<s>4</s>5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.</td></tr>
<tr><td>Intellibind</td><td>No</td><td>There is no assurance that in R1 and R2 that the format designated by the BA or TOP is Mutually Agreed by the parties. It will be essentially impossible for auditors to destinguish what is directed vs. what has been negotiated.</td></tr>
<tr><td colspan="3">Response: There is no need to distinguish between the two cases. The only one that is pertinent is what the two parties have agreed upon. No change made.</td></tr>
<tr><td>Progress Energy</td><td>Yes</td><td>Please include "operational Planning Analyses" in R2 as you have in R1.</td></tr>
<tr><td>California ISO</td><td>Affirmative</td><td>The words “and Operational Planning Analyses” should be added to the end of the first sentence in R2 (the Operational Planning Analysis is included in R1).

A similar addition should be made to R4.</td></tr>
<tr><td colspan="3">Response: By definition, the Balancing Authority can’t perform an Operational Planning Analysis as it is a transmission-oriented task. However, the SDT has added wording to cover analyses.

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform analysis functions and its required Real-time monitoring. The specification shall include:</td></tr>
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Organization	Yes or No	Question 3 Comment
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	If a Transmission Operator or a Balancing Authority is requesting data from another entity, they must demonstrate a reliability impact validating the need for the requested data.
Response: Demonstrating the need would be an onerous task with no reliability benefit. The Transmission Operator and Balancing Authority are constrained as to what they can request by the language in the requirements. They can only ask for what is needed to support their assigned tasks. No change made.		
City of Tallahassee	Affirmative	While it specifies that the examples are only possibilities for evidence, the inclusion of “with acknowledgement” to “web postings” in M2 & M3 for TOP-003-2 will become onerous. It requires another entity to respond in order to have evidence we were compliant.
Response: The SDT believes you meant Measures M3 and M4 but agrees and has changed the measures accordingly. **M3**. Each Transmission Operator shall make available evidence that it has distributed its data specification as developed in Requirement R1to entities that have data required by the Transmission Operator’s ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R2. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ 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 as developed in Requirement R2 to entities that have data required by the Balancing Authority’s analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.		
NIPSCO	Yes	In R3 & R4 the phrase "in meeting its NERC-mandated reliability requirements" is too open-ended and may be difficult to comply with. This should be more specific; what requirements are these.

Organization	Yes or No	Question 3 Comment
Response: The phrase encompasses the approved reliability standards. No change made.		
Associated Electric Cooperative, Inc.	Yes	TOP-003-1 R1, R2, and R3 Guidelines Add: Guidelines Section - These requirements are all written as highly TOP-centric and BA-centric, without regard to the confusion and work-load a single published plan could cause small entities. If hundreds or perhaps thousands of data-points are cited within a uniformly circulated plan, yet some entities provide only one or two obscure points within that plan, then the TOP or BA is being unnecessarily inconsiderate, and should have appropriately filtered that request for their audience. Rationale: Very large TOPs or BAs would benefit from being reminded that they need to consider their audience when sending out plans as data-requests to small entities. There is no need to overwhelm smaller entities with a lot of unrelated data, or data that does not seem to match their own identifiers. We can do better.
Response: The SDT understands the smaller entities perspective. Each entity will be provided a data specification that is unique to them with only the data that they can provide included. No change made.		
Independent Electricity System Operator	Yes	We agree with the addition of R2, but have a concern over Measure M2, which says:M2: Each Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R2.The wording “dated, current, in force” does not reflect what’s in the requirement R2, and is not necessary. This wording pertains to the data retention requirement, which is already included in the second bullet in Section D, 1.3 - Data Retention:”Each Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.”We suggest to remove this wording from M2.
Response: The requirement refers to deadlines which imply a timing element so it is permissible to add ‘dated’ to the measures as adherence to a deadline doesn’t make much sense otherwise. No change made.		

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<tr><td>Ingleside Cogeneration LP - Occidental Chemical Corporation</td><td>Yes</td><td>Although we would prefer to see a consolidated RC-BA-TOP data specification, Ingleside Cogeneration LP agrees that TOP-003-1 is a good first step in that direction. Any help the SDT can provide to reduce overlap in data requests and to drive to a common format is appreciated.</td></tr>
<tr><td colspan="3">Response: The requirement is designed to give the Transmission Operator/Balancing Authority the flexibility it needs to get the data it requires. It is bound by the provision for data needed to support its Real-time monitoring and Operational Planning Analyses. It is absolutely true that different Transmission Operators/Balancing Authorities may be specifying different data in different formats due to their differing operational requirements.</td></tr>
<tr><td>Duke Energy</td><td>Yes</td><td>o R1.1 - Consistent with our Question #1 comment above on using the actual wording of the BOT-approved definition of “Adverse Reliability Impact” since it has not yet been approved by FERC, “Operational Planning Analysis” has likewise not yet been approved by FERC as of the latest version of the Glossary posted on the NERC website, December 13th, 2011. Suggest using the wording of the defined term. If the SDT decides to instead keep the defined term, “Analyses” should be “Analysis”.

o R3 - Current wording is awkward. Suggest rewording as follows: “Each Transmission Operator shall distribute its data specification to entities that have data required for operating analysis assessment processes and reliability monitoring tools used by the Transmission Operator in meeting its NERC-mandated reliability requirements.”

o R4 - Current wording is awkward. Suggest rewording as follows: “Each Balancing Authority shall distribute its data specification to entities that have data required for reliability monitoring tools used by the Balancing Authority in meeting its NERC-mandated reliability requirements.”

o Measures and Data Retention - change to align with suggested R3 and R4 rewording above.</td></tr>
<tr><td colspan="3">Response: Adverse Reliability Impact and Operational Planning Analysis are FERC approved terms. Adverse Reliability Impact was</td></tr>
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Organization	Yes or No	Question 3 Comment
approved on March 16, 2007 and Operational Planning Analysis was approved on March 17, 2011. The Transmission Operator could be running more than one Operational Planning Analysis thus the use of the plural term. No change made. The SDT does not see any additional clarity from the suggested change. However, the SDT has changed Requirements R3 and R4 due to other comments. Measures and Data Retention have been updated accordingly. **R3**. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. **R4**. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.		
American Electric Power	Yes	R5: It should be noted that some of the information that could potentially be requested may already be available, for example on reliability coordinator systems. AEP suggests that the requirement be modified so that it does not unintentionally create an edict to provide "any data" to parties simply because R5 could be interpreted as allowing requests of any kind. The possibility of a dispute resolution process managed by the reliability coordinator(s) might also address these possible scenarios. Such a process should address, at a minimum, specifics such as timing, format and general logistics concerning the requested data. AEP does not currently have any text to suggest in this regard, but asks the SDT to consider such a change.
Response: Requirement R5 is bound by the constraints of Requirements R1 and R2 so that not just any information can be requested. There are arbitration processes available to resolve disputes. No change made.		
Bonneville Power Administration	Yes	BPA is in support of standard TOP-003-1, due to the importance of being able to receive data.
ISO/RTO Standards Review Committee	Yes	

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	
Imperial Irrigation District (IID)	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
PacifiCorp	Yes	
Southwest Power Pool Regional Entity	Yes	
FMPP	Yes	
South Carolina Electric and Gas	Yes	
Oklahoma Gas and Electric	Yes	
Westar Energy	Yes	
Pepco Holdings Inc	Yes	
NV Energy	Yes	
ISO New England Inc.	Yes	
Response: Thank you for your support.		

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: Several comments state that the VSLs for TOP-003-2, Requirement R5 were more stringent or severe than the VSLs for the TOP-003-2, Requirements R1-R4. The SDT views Requirements R1-R4 as enabling requirements for making clear what data is required for the responsible entities in Requirement R5 and believe the VSLs align with the stated purpose of the standard to ensure the Transmission Operator and Balancing Authority have the necessary data "to fulfill their operational planning and Real-Time monitoring responsibilities". Several other comments shared the view that the VRFs and VSL for Requirements R1-R4 were not consistent with Requirement R5. The SDT views Requirements R1 – R4 as enabling requirements leading to Requirement R5. The purpose of TOP-003-2 is to make sure the Transmission Operator and Balancing Authority have the data necessary for fulfilling their functional obligations. Thus, the real crux of the standard is to supply data. No changes were made due to these comments.

Changes made due to comments are:

TOP-001-2, Data Retention: Changed retention requirement for voice recordings to 90 calendar days from three calendar months.

TOP-001-2, Requirement R1 VSL: The Severe VSL was reworded for clarity.

TOP-001-2, Requirement R3 Moderate VSL modified by inserting "affected" for consistency with the requirement and other VSLs.

TOP-001-2, Requirement R5 VSLs: A note prior to the VSLs was removed. The note was a vestige from a previous posting explaining how to use the VSLs when both percentages and integers are used in the VSL. Percentages were removed during that past posting and the note should have been removed as well.

TOP-001-2, Requirement R10 VSLs: Changed "has been" to "had been".

TOP-002-3, Requirement R3 Lower and Severe VSLs were modified based on comments and to make them consistent with Moderate and High VSLs. More specifically, the "whichever is less" language was added to the Lower VSL.

TOP-003-2, Requirements R1 and R2 VSLs: Replaced elements with ~~Parts~~ parts to clarify that it is the ~~Parts~~ parts of the requirements that are missed.

TOP-003-2, Requirements R1 and R2, Severe VSL: Changed “four or more” to “four” since there are only four parts.

TOP-003-2, Requirements R3 and R4 VSLs: Added “boiler plate” explanation for how to select if the integer or percentage value is used in selecting the VSL.

No changes were made for the following comments:

TOP-001-2, Requirements R3, R5, and R6 VSLs: A few comments suggested adding percentages to the integer VSLs. The SDT did not believe that probable sample sizes warranted use of percentages.

TOP-001-2, Requirement R5 VSL – Several comments indicated the VSL should be binary and Severe. The SDT disagrees that the VSL ought to be binary. Failure to notify one Transmission Operator of an Adverse Reliability Impact is not as Severe as failing to notify the Reliability Coordinator. Failure to notify the Reliability Coordinator is a Severe VSL. If the Reliability Coordinator knows, then the Reliability Coordinator will ensure the Adverse Reliability Impact is addressed.

TOP-003-2, Requirement R5 VSLs: Several comments indicated concern that the requirement could not be partially satisfied. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc.

Changes made are reflected below:

TOP-001-2, R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, ~~unless~~and such action would have violated safety,

				equipment, regulatory, or statutory requirements.
TOP-001-2, R3	The Transmission Operator did not inform one other Transmission Operator that is known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis

TOP-001-2, R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, ha~~s~~d been exceeded.

TOP-002-3, R3	The Transmission Operator did not notify one NERC registered entity or 5% or less of the NERC registered entities whichever is less identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two NERC registered entities or more than 5% and less than or equal to 10% of the NERC registered entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three NERC registered entities or more than 10% and less than or equal to 15% of the NERC registered entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more NERC registered entities or more than15% of the NERC registered entities identified in the plan(s) as to their role in the plan(s).

TOP-003-2, R1	The Transmission Operator did not include one of the required ~~elements~~ parts (Part 1.1 through Part 1.4) of the documented	The Transmission Operator did not include two of the required ~~elements~~ parts (Part 1.1 through Part 1.4) of the documented	The Transmission Operator did not include three of the required ~~elements~~ parts (Part 1.1 through Part 1.4) of the documented	The Transmission Operator did not include four ~~or more~~ of the required ~~elements~~ parts (Part 1.1 through Part 1.4)

	specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring.	of the documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

TOP-003-2, R2	The Balancing Authority did not include one of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its required analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its required analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their required analysis functions and Real-time monitoring.	The Balancing Authority did not include four ~~or more~~ of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their required analysis functions and Real-time monitoring.

				OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its required analysis functions and Real-time monitoring.

Organization	Yes or No	Question 4 Comment
Luminant Energy	Abstain	The comments below are in reference to the VSL for TOP-003-2 R5: The VSL for TOP-003-2 R5 places a more stringent severity level on the entities receiving the data requests than it places on the entities that are responsible for creating the data requests. As such, I would suggest changing the VSL for TOP-003-2 R5 to the following: Lower: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy one of the obligations of the documented specification for data. Moderate: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy two of the obligations of the documented specification for data. High: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy three of the obligations of the documented specification for data. Severe: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy four or more of the obligations of the documented specifications for data.
Response: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation should only occur		

Organization	Yes or No	Question 4 Comment
for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. No change made.		
Lincoln Electric System (LES)	No	The word "affected" should be added to the Moderate VSL for TOP-001-2 R3 following "...known or expected to be affected by an actual...".
Response: The SDT agrees and has modified the Moderate VSL. See the redlined VSL in the Summary Consideration for this question to view the changes.		
Duke Energy	No	o TOP-001-2, R8 - Consistent with R3, the Time horizon for R8 should only be Operations Planning. o TOP-001-2 VSLs for R8 and R9 should be changed consistent with our suggested revisions to the requirements. Also see comment below regarding use of percentage ranges. o TOP-002-3 VSLs for R3 - the addition of the percentage range on the Lower VSL makes no sense. The "whichever is less" phrase on the other VSLs could push a violation into a higher VSL because of the percentage range. For example, if the TOP had 10 entities to notify and failed to notify one, then it would be a Moderate violation (10%) instead of Lower. If the TOP had 100 entities to notify and failed to notify four (less than 5%), then it would still be a Severe violation. o TOP-003-2 VSLs for R1 - "Analyses" should be "Analysis", since "Operational Planning Analysis" is a defined term. o TOP-003-2 VSLs for R2 - Severe VSL should just say "four" instead of "four or more" because there are only four required elements. o TOP-003-2 VSLs for R3 and R4 - the addition of the percentage range on the Lower VSL makes no sense. See comment on TOP-002-3 VSLs for R3 above.
Response: TOP-001-2, R8 – The SDT agrees and has modified the Time Horizon for R8 to only cover Operations Planning.		

Organization	Yes or No	Question 4 Comment
TOP-001-2, R8 and R9 – Please see our response to your comments in Q1. TOP-002-3, R3 – The utilization of the "whichever is less" language has been vetted by NERC and is used in other standards. There is an explanatory statement prior to the VSLs for Requirement R3 that details how the VSLs are determined in the examples provided. The SDT did add "whichever is less" in the Lower VSL and "than" in the Severe VSL. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2, R1 – The SDT disagrees. "Analyses" is the plural form of "analysis" and its use is consistent with the requirement. The SDT intended for the data specification to apply to all the analyses that the Transmission Operator must perform and not a single analysis. Otherwise, one could interpret the requirement to require a separate data specification for every analysis performed by the Transmission Operator. Definitions in the NERC Glossary are regularly used in singular or plural form in other standards. No change made. TOP-003-2 R2 – The SDT agrees and has modified the Severe VSL for R2 and R1 as well. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2 VSLs R3 and R4: The utilization of the "whichever is less" language has been vetted by NERC and is used in other standards. The SDT has added an explanatory statement prior to the VSLs for R3 and R4 that explains how the VSL is determined in the examples provided.		
Texas Reliability Entity	No	Regarding the VSL for TOP-001-2 R5, we suggest that it be based on a percent of applicable TOPs rather than number of TOPs, which would accommodate various sized entities. Regarding the VSLs for TOP-001-2 R9 and R11, we recommending adding a time duration reference relating to SOL violations, even if it is not a definite number of minutes. Referring to the VSLs for TOP-003-2 R1, there are only four elements listed, so the reference to "four or more" is nonsensical. Also, there is no difference between omitting four elements and not providing a documented specification at all. Finally, the four listed elements do not appear to have equal importance - perhaps the VSL levels should be assigned based on which elements are missing.
Response: TOP-001-2 R5 – Because VSLs using percentages must use the 5, 10, 15%, etc., scale, the SDT believes using percentages will actually escalate the VSLs for all entities more rapidly and result in a situation where the some levels are never used. In the vast		

Organization	Yes or No	Question 4 Comment
majority of situations, a Transmission Operator will have to notify, at most, its immediate neighboring Transmission Operator-s. A Transmission Operator would have to have more than 26 neighboring Transmission Operator-s before each VSL could be used. The SDT does not believe there will be any Transmission Operator with that many neighboring Transmission Operator-s. No change made. TOP-001-2 R9 & R11 – The timing requirement is implicitly contained within Facility Rating or Stability criteria. No change made. TOP-003-2 R1 – The SDT has changed "four or more" to "four". The SDT understands that failing to meet all four parts may be viewed by some as not providing any data specification. Others may not share that view and may believe that some document could be provided that does not meet any of the requirement parts. Either way the violation will be assessed at a Severe VSL. Additionally, the SDT does not believe missing any one of the four parts will contribute to a greater violation of the requirement than the other parts. See the redlined VSL in the Summary Consideration for this question to view the changes.		
E.ON Climate & Renewables	No	Considering the unknowns in the data specifications, the high severity factor on R5 seems unreasonable.
Kansas City Power & Light	No	The VSL for TOP-003-2, R5 does not recognize partially satisfying a request for data. Recommend the SDT consider a graduated set of severity levels similar to the other requirements in TOP-003-2.
Kansas City Power & Light	Negative	The VSL for TOP-003-2, R5 does not recognize partially satisfying a request for data. Recommend the SDT consider a graduated set of severity levels similar to the other requirements in TOP-003-2.
Response: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation should only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. No change made.		
ReliabilityFirst	No	For the TOP-001-2 standard, ReliabilityFirst disagrees with the VSLs for the following

Organization	Yes or No	Question 4 Comment
		reasons:1. VSLs for R3, R5 and R6 - ReliabilityFirst recommends adding the gradated language of “or X% or less of the entities whichever is less” to the VSLs (this is consistent with the language stated in the TOP-002-3 and TOP-003-2 VSLs). This is needed for smaller Transmission Operators which may have less than four other TOPs to inform. 2. Note in front of VSL 5 - ReliabilityFirst recommends removing the note in front of VSL5 since the note is contrary and is in conflict on how the VSL is set up.
Response: TOP-001-2 R3, R5, and R6: Because VSLs using percentages must use the 5, 10, 15%, etc., scale, the SDT believes using percentages will actually escalate the VSLs for all entities more rapidly and result in a situation where the some levels are never used. In the vast majority of situations, a Transmission Operator will have to notify, at most, its immediate neighboring Transmission Operators and maybe a few additional registered entities. A Transmission Operator would have to notify more than 26 entities before each VSL could be used. The SDT does not believe there will be any Transmission Operator with that many entities to notify. In this case, the SDT believes use of one, two, three, and four represents the best balance between large and small entities. No change made. TOP-001-2 R5 – The SDT has removed the note.		
American Electric Power	No	In general, the VRFs and VSLs are too severe and punitive. Because of this, as well as our objections with the redundancy of requirements in TOP-001-2, AEP cannot support the proposed VRFs and VSLs.
Response: The SDT has not made any changes because of the lack of specificity with the comments.		
Ameren	No	See comments in question 5 regarding VRF.
Response: See response to Q5.		
ACES Power Marketing Member Standards Collaborators	No	The VSLS for TOP-002-3 Requirements R1 and R2 could have more levels based on the number of days for which there is not a plan or Operational Planning Analysis.

Organization	Yes or No	Question 4 Comment
Response: The requirement was written in singular form because the SDT believes it is very important to not miss a single day. Since the requirement is for a single day, FERC VSL criteria will not allow a VSL to accumulate the number of days. No change made.		
ISO/RTO Standards Review Committee	No	TOP-001-2, R3 Moderate VSL - the word "affected' has been omitted and needs to be inserted. TOP-003-2, R1 & R2 - The use of the term 'element' in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 - The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn't this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by the ISO/RTO Standards Review Committee concerning the need to build some flexibility into the VSL for TOP-003-2 R5.
Pepco Holdings Inc	No	PHI supports the comments provided by the ISO/RTO Standards Review Committee.
Southwest Power Pool Reliability Standards Development Team	No	TOP-001-2, R3 Moderate VSL - the word "affected' has been omitted and needs to be inserted. TOP-003-2, R1 & R2 - The use of the term 'element' in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 - The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn't this requirement have feathered VSLs such that the more data points missing the more severe the violation would

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		become?
Nebraska Public Power District	No	TOP-001-2, R3 Moderate VSL - the word “affected’ has been omitted and needs to be inserted. TOP-003-2, R1 & R2 - The use of the term ‘element’ in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 - The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn’t this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
Response: TOP-001-2 R3 – The SDT agrees and has modified the Moderate VSL. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2 R1 and R2 – The SDT agrees this could cause confusion and has modified the VSLs to use parts in place of elements. This is consistent with the terminology NERC filed with FERC when they eliminated sub-requirements. Thus, the VSLs apply to Parts 1.1 through 1.4 and 2.1 through 2.4. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2, R5 - The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. No change made.		
Associated Electric Cooperative, Inc.	No	TOP-001-2-R1 VSL Change: “unless such action would violate”To: “and such action would have violated” Rationale: State the issue rather than recite the requirement. TOP-001-2-R8 VSL Change: “whichever is less” To: “whichever is greater” Rationale:

Organization	Yes or No	Question 4 Comment
		Intent TOP-001-2-R10 VSL Change: “has been” To: “had been” Rationale: grammatical TOP-002-3-R1 Lower VSL: Duplicate Severe VSL wording then append “, on one day within a calendar year.” TOP-002-3-R1 Moderate VSL: Duplicate Severe VSL wording then append “, on two non-consecutive days within a calendar year.” TOP-002-3-R1 High VSL: Duplicate Severe VSL wording then append “, on three non-consecutive days or two consecutive days within a calendar year” TOP-002-3-R1 Severe VSL: Append: “, on four or more days, or three consecutive days within a calendar year.” TOP-002-3-R1 VSL changes Rationale: Eliminate zero-defect expectation TOP-002-3-R3 VSL Change: “of the NERC” To: “, whichever is greater, of the NERC” Rationale: precision and alignment with wording in TOP-01-2 R8 VSLs.
Response: TOP-001-2, R1 – The SDT agrees and has modified the VSL similar to your request. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-001-2, R8 - The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. The SDT has added an explanatory statement prior to the VSLs for R8 that explains how the VSL is determined. No change made. TOP-001-2, R10 – The SDT agrees and has corrected the VSL. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-002-3, R1 – The SDT disagrees with gradating the VSLs on this requirement. The SDT believes that the requirement is of such importance that it wrote the requirement in singular form. Thus, each failure to have an OPA is a separate violation. This is also consistent with FERC VSL Guidelines. No change made. TOP-002-3, R3 – The SDT added the missing “whichever is less” language to the Lower VSL. The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. The SDT has added an explanatory statement prior to the VSLs in R3 that explains how the VSL is determined. See the redlined version in the Summary Consideration for this question to see the		

Organization	Yes or No	Question 4 Comment
changes.		
Manitoba Hydro	No	TOP-002-3 R3 VSL - The wording of the VSL is unclear. Manitoba Hydro suggests changing the wording of the VSL as follows (the severe VSL of TOP-002-3, R3 is provided as an example): 'The Transmission Operator did not notify either four or more NERC registered entities, or more than 15% of the NERC registered entities identified in the plan(s) as to their role in the plan(s).
Response: The SDT added the missing "whichever is less" language to the Lower VSL. The utilization of the "whichever is less" language has been vetted by NERC and is used in other standards. There is an explanatory statement prior to the VSLs in R3 that explains how the appropriate VSL is determined. See the redlined version in the Summary Consideration for this question to see the changes.		
United Illuminating Company	No	TOP-003 R5 has only a severe VSL. This seems unequitable to the data providors who are responsible for tens of thousands of data points, some redundant. Especially since State Estimators are designed to estimate for bad or missing data. UI disagrees with vsl for R5 which is severe only. UI is concerned that failing to provide a single data point for a partial period would result in a severe violation reagardless of all the other data being transmitted. UI notes that with in TOP-001 (R6 and R8) and TOP-02 R3 the SDT managed to create VSL's that allowed for percentage measure or quantity measure. A similar approch should be done with TOP-003 R5. Failure to transmit a single point of data will not result in a cascade or directly affect the electrical stae of the BES.
Response: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT		

Organization	Yes or No	Question 4 Comment
believes a single Severe VSL is appropriate. Writing VSLs based on the number of data points provided would further complicate compliance enforcement actions for the responsible entity by requiring them to provide evidence of the number of data points they are required to provide to demonstrate sample size is not practical. No change made.		
South Carolina Electric and Gas	No	
Response: Without a specific comment, the SDT is unable to respond.		
Beaches Energy Services	Negative	It would seem that the VSL for TOP-001 R5 ought to be binary, not informing any TOP of a potential Adverse Reliability Impact seems a Severe violation. It does pose the question, which TOPs? All of them in the interconnect? Only neighboring TOPs? Only TOP's in the RC area? TOP-003 VRFs - there should not be an inconsistency between R1, R2 and R3 for creation and distribution of data specifications being Low VRF, but supplying the data required is a Medium. They should be the same, e.g., if a RC, BA or TOP doesn't tell the other entities what data is required, how can that entity know what to supply? VSLs for R1 and R2, "required element" as used in the VSLs should be replaced with "specifications" to coincide with the term used in the requirement. VSL for R5 should not be binary. It is inconsistent with other requirements. E.g., If in R4, a BA or TOP did not distribute to 3 entities, and therefore did not receive any data from those 3 entities, then, that is a low VRF and High VSL to the BA for missing all of the data from 3 entities. However, in R5 if an entity misses one piece of data from that entity it is a Medium VRF and a Severe VSL. This is inconsistent.
Response: TOP-001, R5 – The SDT disagrees that the VSL ought to be binary. Failure to notify one Transmission Operator of an Adverse Reliability Impact is not as Severe as failing to notify the Reliability Coordinator. Failure to notify the Reliability Coordinator is a Severe VSL. If the Reliability Coordinator knows, then the Reliability Coordinator will ensure the Adverse Reliability Impact is addressed. The answer to the question of which Transmission Operators is found within the requirement. It is the Transmission Operators that are “known or expected” to be affected by the Adverse Reliability Impact. That could be immediate neighbors or		

Organization	Yes or No	Question 4 Comment
broader if the Transmission Operator's operations are "known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas". No change made. TOP-003 – The SDT views development and communication of a data specification as an enabling requirement for ensuring the Transmission Operator and Balancing Authority have the necessary data. Actual supply of the data is what is most important in this requirement. The VRFs reflect this relative importance. No change made. The SDT agrees that "elements" in the VSLs for Requirements R1 and R2 is not the correct word and has modified the VSLs to use parts in place of elements. This is consistent with the terminology NERC filed with FERC when they eliminated sub-requirements. See the redlined version in the Summary Consideration for this question to see the changes. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. Writing VSLs based on the number of data points provided would further complicate compliance enforcement actions for the responsible entity by requiring them to provide evidence of the number of data points they are required to provide to demonstrate sample size and is not practical. No change made.		
California ISO	Negative	The VSL table states the following as Severe for TOP-001 R9: The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria. We cannot agree with this wording until the meaning of "continuous" is better defined.
Response: The language quoted in the comment is not from the most recent VSL in TOP-001-2, Requirement R9. For example, the VSL mentions nothing about 30 minutes. The SDT intended the literal meaning of continuous. Thus, the duration would start over if the Transmission Operator managed to temporarily bring the operation of the SOL back within the limit. No change made.		
Florida Municipal Power Agency	Negative	TOP-001-2 R5 and R9 VRFs should be High, especially R9 It would seem that the VSL for R5 ought to be binary, not informing any TOP of a potential Adverse Reliability Impact seems a Severe violation. It does pose the question,

Organization	Yes or No	Question 4 Comment
		which TOPs? All of them in the interconnect? Only neighboring TOPs? Only TOP's in the RC area? The VSL for R8 for Lower, Moderate and High ought to be reworded to avoid the ambiguous reference and make sure that IROLs are always Severe, e.g., (one, two, or three) SOLs that are not IROLS or more than (X% to Y%) .... TOP-002-3 VRF's and VSL's look good TOP-003-2 VRFs - there should not be an inconsistency between R1, R2 and R3 for creation and distribution of data specifications being Low VRF, but supplying the data required is a Medium. They should be the same, e.g., if a RC, BA or TOP doesn't tell the other entities what data is required, how can that entity know what to supply? VSLs for R1 and R2, "required element" as used in the VSLs should be replaced with "specifications" to coincide with the term used in the requirement VSL for R5 should not be binary. It is inconsistent with other requirements. E.g., If in R4, a BA or TOP did not distribute to 3 entities, and therefore did not receive any data from those 3 entities, then, that is a low VRF and High VSL to the BA for missing all of the data from 3 entities. However, in R5 if an entity misses one piece of data fro that entity it is a Medium VRF and a Severe VSL. This is inconsistent.
City of Vero Beach	Negative	TOP-001 R5 and R9 VRFs should be High, especially R9 It would seem that the VSL for R5 ought to be binary, not informing any TOP of a potential Adverse Reliability Impact seems a Severe violation. It does pose the question, which TOPs? All of them in the interconnect? Only neighboring TOPs? Only TOP's in the RC area?

Organization	Yes or No	Question 4 Comment
		The VSL for R8 for Lower, Moderate and High ought to be reworded to avoid the ambiguous reference and make sure that IROLs are always Severe, e.g., (one, two, or three) SOLs that are not IROLS or more than (X% to Y%) .... TOP-003 VRFs - there should not be an inconsistency between R1, R2 and R3 for creation and distribution of data specifications being Low VRF, but supplying the data required is a Medium. They should be the same, e.g., if a RC, BA or TOP doesn't tell the other entities what data is required, how can that entity know what to supply? VSLs for R1 and R2, "required element" as used in the VSLs should be replaced with "specifications" to coincide with the term used in the requirement VSL for R5 should not be binary. It is inconsistent with other requirements. E.g., If in R4, a BA or TOP did not distribute to 3 entities, and therefore did not receive any data from those 3 entities, then, that is a low VRF and High VSL to the BA for missing all of the data from 3 entities. However, in R5 if an entity misses one piece of data from that entity it is a Medium VRF and a Severe VSL. This is inconsistent.

Response: TOP-001, R5 VRF – The SDT disagrees. There is a similar requirement (Requirement R5) in proposed IRO-014-2 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities: TOP-001-2 for Transmission Operators and IRO-014-2 for Reliability Coordinators. The assignment of the Medium VRF was made based on the premise that failure to coordinate activities, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a “High” VRF there should be the expectation that failure to meet the required performance “will” result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to coordinate activities. While the SDT agrees that, under some circumstances, it is possible that a failure to coordinate activities may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to coordinate would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to coordinate activities, it would still be expected to handle the situation if it occurred.

TOP-001-R9, VRF – The SDT disagrees that the VRF should be High for an SOL. SOLs do not have the same level of importance as an IROL. No change made.

Organization	Yes or No	Question 4 Comment
TOP-001, R5 VSL – The SDT disagrees that the VSL ought to be binary. Failure to notify one Transmission Operator of an Adverse Reliability Impact is not as Severe as failing to notify the Reliability Coordinator. Failure to notify the Reliability Coordinator is a Severe VSL. If the Reliability Coordinator knows, then the Reliability Coordinator will ensure the Adverse Reliability Impact is addressed. The answer to the question of which Transmission Operators is found within the requirement. It is the Transmission Operators that are "known or expected" to be affected by the Adverse Reliability Impact. That could be immediate neighbors or broader if the Transmission Operator's operations are "known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas". No change made. TOP-001-2, R8 – IROLs are not considered in this requirement. It only pertains to selected, identified SOLs which are not IROLs. No change made. To further clarify the VSLs, a "boiler plate" explanation for how to select the VSL has been added above the VSLs. TOP-003 – The SDT views development and communication of a data specification as an enabling requirement for ensuring the Transmission Operator and Balancing Authority have the necessary data. Actual supply of the data is what is most important in this requirement. The VRFs reflect this relative importance. No change made. TOP-003, R1 and R2 - The SDT agrees that "elements" in the VSLs for Requirements R1 and R2 is not the correct word and has modified the VSLs to use parts in place of elements. This is consistent with the terminology NERC filed with FERC when they eliminated sub-requirements. See the redlined versions in the Summary Consideration for this question to view the changes. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. Writing VSLs based on the number of data points provided would further compliance enforcement actions for the responsible entity by requiring them to provide evidence of the number of data points they are required to provide to demonstrate sample size and is not practical. No change made.		
CPS Energy	Negative	Quality Review of VRF's needed.
Response: A quality review of all VRF's is part of the standard review cycle for all projects.		

Organization	Yes or No	Question 4 Comment
Intellibind	Negative	Data retention requirements are not consistent with other standards that only require maintaining logs and voice recordings for 90 days. This adds confusion to compliance recordkeeping where some records are purged every 90 days, but that records of certain topic must be maintainted for longer periods. Retention of data should be done on an identified amount of days (eg. 30, 60, 90) as apposed to "consecutive months" since computer systems primarily use a count of days, and do not necessarily distiguish a calandar month for purging records. As stated the retention period will add addtional adminsitratve overhead and expense to ensuring compliance to these requirements.
Response: The general language of the data section is provided by NERC staff. The SDT found only one instance of calendar month in the standards. It stated that voice recordings shall be retained for three calendar months. The SDT changed that reference to 90 calendar days.		
Liberty Electric Power	Negative	I do not understand why a TO or BA who fails to send a data request to a generator would receive a "Low" VSL while that same generator would receive a "severe" VSL for not satisfying all the requirements of the data request.
Response: The SDT views Requirements R1 – R4 as enabling requirements. The purpose of TOP-003-2 is to make sure the Transmission Operator and Balancing Authority have the data necessary for fulfilling their functional obligations. Thus, the real crux of the standard is to supply data. Everything else is simply administrative to enable the sharing of that data. If the generator owner or generator operator does not receive a data specification, they have no obligation under the standards to supply data and cannot be held in violation of the Requirement R5. Thus, no situation could ever exist where a Balancing Authority or Transmission Operator is held in violation of Requirements R3 or R4 for failing to send the data specification to a generator owner or generator operator and then that same generation owner or generation operator is held in violation of Requirement R5. No change made.		
Bonneville Power Administration	Negative	BPA is voting "No" for VSLs/VRFs for R8 of TOP-001-2, R3 of TOP-002-3, and R3/R4 of TOP-003-2 because they are written in a confusing manner. BPA recommends using 1, 2, 3, or 4 SOLs instead of trying to including things like "more than 10%, but less than 15%", particularly since the requirement is to take the lesser or that or the 1, 2, 3, or 4 SOLs.
Response: The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. There was an explanatory statement prior to the VSLs in some of these requirements that explains how the appropriate VSL is determined. It was		

Organization	Yes or No	Question 4 Comment
missing before others. The explanatory statement has been added where appropriate.		
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	Ingleside Cogeneration LP believes that the requirements applicable to a GO/GOP carry VRFs, VSLs, and Time Horizons consistent with those assigned to similar requirements.
NIPSCO	Yes	None at this time
Southwest Power Pool Regional Entity	Yes	
FirstEnergy	Yes	
Imperial Irrigation District (IID)	Yes	
Dominion	Yes	
FMPP	Yes	
Muscatine Power and Water	Yes	
Independent Electricity System Operator	Yes	
Dairyland Power Cooperative	Yes	
Omaha Publc Power District	Yes	
US Bureau of Reclamation	Yes	
Response: Thank you for your support.		

5. **If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: The majority of comments received for this question were re-statements of earlier comments or simple requests for clarification. No changes were made to any requirements due solely to comments in this question.

Organization	Yes or No	Question 5 Comment
Potomac Electric Power Co.	Abstain	Pepco Holdings Inc. supports the comments offered by EEI.
Response: EEI did not supply comments to this posting.		
Great River Energy	Affirmative	Comments submitted with the MRO NSRF
Minnkota Power Coop. Inc.	Negative	Please see comments submitted by the MRO NSRF.
Response: See the responses to MRO NSRF comments in Q1 – Q4.		
SERC Reliability Corporation	Affirmative	Don't forget to synch the definition of Directive with COM-002.
Response: The SDT is in contact with, and coordinating as necessary, with the SDT that is working on COM-002.		
Florida Municipal Power Pool	Affirmative	Implementation Comments submitted. Added here incase they did not go through. Comments for Project 2007-03 Real-Time Transmission Operations The changes to the TOP Standards are a great improvement over the existing Standards; however, I think because they are so much better than the existing Standards that they should be implemented as soon as possible. I think one year is enough time to make the necessary changes to processes, procedures and documentation. Even more important than the implementation of the new Standards is the deletion of the existing Standards as soon as possible. Some of the existing Requirements are worthless and unenforceable. The SDT has determined that some of the existing

Organization	Yes or No	Question 5 Comment
		Requirements are replaced by new requirements and they will need to be enforceable until the new Requirements are enforceable. However, the SDT has identified some Requirements that are either no longer necessary or covered by existing Requirements or the Functional Model (see mapping document excerpts below): o PER-001-0 R1 o TOP-001-1 R1 o TOP-002-2 R2 o TOP-002-2 R7 o TOP-002-2 R8 o TOP-002-2 R18 o TOP-002-2 R19 Deleting these Requirements does not need to have an implementation period. They can be deleted as soon as approved by FERC with no waiting. TOP-002-2 R8 is the most important Requirement to be deleted as soon as approved because it never should have been a requirement of the Balancing Authority. To make matters worse this Requirement is in the tier 2 Requirements for actively monitored Requirements for 2012! Also the SDT has identified some Requirements that apply to the Balancing Authority that are either no longer necessary (or even NEVER should have been applicable) or covered by existing Requirements or the Functional Model (see mapping document excerpts below): o TOP-002-2 R1 o TOP-002-2 R5 o TOP-002-2 R6 o TOP-002-2 R10 The SDT states for TOP-002-2 R10: “The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority.” Obvious wrong Requirements like TOP-002-2 R10 should be deleted ASAP. They are a compliance conundrum, and open to compliance fines! From the Mapping Document: PER-001-0 R1 is deleted because “In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator’s authority to issue directives arises out of the Commission’s approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted.” TOP-001-1 R1 is deleted because “This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn’t alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible

Organization	Yes or No	Question 5 Comment
		entity. These needed actions required for reliability of the bulk power system have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power system is not adversely affected by the deletion of this requirement." TOP-002-2 R1 is deleted for the Balancing Authority because "The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-1 and must take action per approved EOP-002-2.1, Requirement R6 and thus the Balancing Authority part of this sentence can be deleted. Second sentence - Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities as per their certification as NERC registered entities. " TOP-002-2 R2 is deleted because "The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted. " TOP-002-2 R5 is deleted for the Balancing Authority because "The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model." TOP-002-2 R6 is deleted for the Balancing Authority because "The part of this requirement dealing with the Balancing Authority is replaced by approved BAL-002- 0 and proposed BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of

Organization	Yes or No	Question 5 Comment
		operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. " TOP-002-2 R7 is deleted because "The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-1, Requirement R2 and therefore this requirement is redundant and can be deleted as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority!" TOP-002-2 R8 is deleted because "The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted as all elements of the requirement are now covered in other standards. Voltage and reactive power balance are the responsibility of the Transmission Operator (not the Balancing Authority) and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority!!" TOP-002-2 R8 is the most important Requirement to be deleted as soon as approved because it should never have been a requirement of the Balancing Authority. To make matters worse this Requirement is in the tier 2 Requirements for actively monitored Requirements for 2012! TOP-002-2 R10 is deleted for the Balancing Authority because "The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority." TOP-002-2 R18 is deleted because "This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. " To make matters worse this Requirement is the tier 1 Requirements for actively monitored Requirements for 2012! Which means NERC views this as an important Requirement to reliability. But I agree with the SDT that this Requirement adds NO reliability benefit. TOP-002-2 R19 is deleted because "This is part of an entity's certification and is no longer required in standards. "

Organization	Yes or No	Question 5 Comment
Response: The SDT appreciates your concerns. However, no change is being made due to the following reasons: 1. The requirements being cited are in service today and are being 'followed' by registered entities with minimal problems. The main difference in this project from today is the formalization of some of the requirements particularly the data specification. 2. This is the only comment received on this issue. Other entities are apparently okay with the status quo. **3.** Setting up an implementation plan with the suggestions above would make for a logistical nightmare with no reliability benefit. **4.** The SDT has shortened the effective date to 12 months for all requirements except the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
MEAG Power	Affirmative	MEAG Power supports the comments of Austin Energy.
Response: Austin Energy did not supply any comments to this posting.		
Portland General Electric Co.	Affirmative	PGE agrees with the WECC Position paper on Real-Time Operations.
Response: Without specific comments to this posting the SDT is unable to respond.		
Illinois Municipal Electric Agency		Illinois Municipal Electric Agency appreciates SDT efforts to develop a sixth draft for this proposed Reliability Standards development. While we realize the SDT will never be able to resolve all concerns, it appears from our own review and our review of other entity comments that additional revisions are needed to achieve a level of quality that will minimize difficulties complying with these Reliability Standards.
Baltimore Gas & Electric Company, Constellation Energy Commodities Group	Affirmative	We are voting affirmatively because we support the improvements achieved by the drafting team work so far. However, we raised remaining concerns with the standard proposal on the comment form submitted on behalf of CCG, CECD and CPG. We expect the drafting team to continue to make clarifying changes until the end of this stakeholder process. The greater the clarity in the final product, the less risk of contradictory perspectives on compliance.

Organization	Yes or No	Question 5 Comment
Response: The SDT will continue to work to refine the standards until the end of the stakeholder process.		
Santee Cooper	Negative	"Internal area reliability" needs to be clarified.
Response: Requirement R8 was modified to replace the phrase “its internal area reliability” with “reliability internal to its Transmission Operator Area”. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Fort Pierce Utilities Authority	Negative	Please see the joint comments submitted by Florida Municipal Power Agency (FMPA) filed through the formal comment process.
Response: See response to FMPA comments in Q1 – Q4.		
Consolidated Edison Co. of NY, Inc.		Comments: TOP-001-2 is referencing a NERC definition for “Reliability Directive” which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of “Reliability Directive” would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for “Reliability Directive” changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an “across the board” usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.” It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts

Organization	Yes or No	Question 5 Comment
		compliance to COM-002.
Orange and Rockland Utilities, Inc.		Comments: TOP-001-2 is referencing a NERC definition for "Reliability Directive" which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of "Reliability Directive" would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for "Reliability Directive" changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an "across the board" usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts." It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team as well.		
Georgia System Operations		GSOC believes that all 3 standards should be voted on together in one vote. They are too inter-related. One or two of these should not be approved if one of them is not approved.
Response: The purpose of separating the votes at this stage was to provide additional feedback to the SDT. The three standards will be filed together once all 3 have been approved by the industry.		
Texas Reliability Entity		Referring to the posted "Issues Database," under Order 693 Â¶ 1604/1608, the red-lined language is not actually in the referenced requirement. Does the drafting team

Organization	Yes or No	Question 5 Comment
		contend that the proposed requirements satisfy this FERC directive? Referring to the posted “Issues Database,” under Order 693 Â¶ 1636 (TOP-004), this document suggests that a 30-minute limit is contained in the requirements, but that limit is not in the language that is now posted. Does the drafting team contend that the proposed requirements satisfy this FERC directive? In general, NERC needs to make sure the Issues Database is consistent with the latest draft of the requirements. The VRF/VSL Assignment Document needs to be cleaned up. There are numerous references to incorrect requirement numbers. On page 3, TOP-001-2 Requirement R3 is struck from the list of “High” VRFs, but it is assigned a high VRF in the posted standard. Also, the title of TOP-001-2 is stated incorrectly in this document (at the beginning).
Response: 1604 - The SDT agrees that the posted language was not updated in the issues database to reflect the latest version of the standard. However, the context hasn’t changed and the SDT does believe that the suggested requirement addresses the directive. The issues database language has been cleaned up appropriately. No other change made. 1636 – The issues database language was not properly updated when the requirement was changed from a 30 minute perspective to a limits perspective. However, the context hasn’t changed and the SDT does believe that the suggested requirement addresses the directive. The issues database language has been cleaned up appropriately. No other change made. The SDT has reviewed the VRF/VSL document and made changes as appropriate. The SDT does not understand the comment. The posted requirement is assigned a high VRF. The VRF/VSL document states that Requirement R3 has been assigned a high VRF. There does not appear to be a discrepancy. No change made. The title has been corrected in the VRF/VSL document.		
American Transmission Company, LLC		ATC feels this project has diminished a good base of existing standards, and introduced ambiguity, and vagueness. Additionally, we feel certain key aspects of the current standards were removed for example, “Clear, decision making authority” from System Operators, and the need for “Uniform Line Identifiers”, which is not in

Organization	Yes or No	Question 5 Comment
		the interest of Reliability.
Response: The SDT has provided reasons for deleting the two phrases referenced above in the mapping document accompanying this posting. To date, the SDT has seen no justifications for restoring the cited phrases. No change made.		
SERC OC Standards Review Group		Data retention requirements for TOP-001-2. TOP-002-3 and TOP-0003-2 need to align with the expectations of the compliance entity."The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Owensboro Municipal Utilities	Negative	Please refer to SERC Operating Committee Comments.
Entergy, Entergy Services, Inc.	Negative	o Comments submitted - see SERC OC Standards Review Group comments.
Response: The data retention requirements for all 3 standards follow the established guidelines and were reviewed as part of the quality review process prior to posting. No change made.		
GTC		Demonstrating providing all data specifications for real time operations horizon is very prescriptive in nature and could have unanticipated "compliance documentation" consequences when data or the transfer method is unavailable (e.g., when an RTU goes down).
Response: Demonstrating the need would be an onerous task with no reliability benefit. The Transmission Operator and Balancing Authority are constrained as to what they can request by the language in the requirements. They can only ask for what is needed to support their assigned tasks. No change made.		
FirstEnergy		FE has the following comments and suggestions:1. In the mapping document, it shows that PRC-001-1 R2 will be replaced by the new TOP-003-2 R5. However, we do not see a new version of PRC-001-2 posted. Also, the implementation plan makes no reference to PRC-001.

Organization	Yes or No	Question 5 Comment
		2. The mapping document does not seem to be referencing the correct version of TOP-005 (should be Version 2a). Also, the mapping document is not referencing the correct requirement for TOP-006-1 R4 (the RC should not be shown as applicable).
Response: The PRC standard was inadvertently left out of this posting but has been provided as part of the next posting. The Implementation Plan has been updated as well. The correct reference should be TOP-005-2a and the mapping document has been changed as necessary to reflect this. Requirement R4 has been corrected.		
NV Energy		In the re-draft of these three standards, TOP-001, -002, and -003, we seem to have lost the concept of Planned Outage Coordination for BES facilities (a whole Standard was devoted to the process). In viewing the mapping document, it is stated that the requirements for such outage coordination that used to reside in TOP-003-1 are now replaced by R1 and R2 of TOP-003-2. If this is the case, then all of the activities of outage coordination are to be encapsulated in the clause "documented specification for the data necessary for it to perform its required Operational Planning Analyses..." While it may be covered in this extremely broad clause, the SDT nevertheless gave prominence to the coordination of telemetry outages within a specific requirement R6 of TOP-001-2. If telemetry outages have a separate requirement, then shouldn't planned outage coordination of BES facilities rise to the level of importance that would merit its own requirement?
Response: Since telemetry outages might take out the very mechanism relied upon for the transfer of data in TOP-003-2, the SDT believed that a separate requirement was necessary for such outages. Also, telemetry is part of infrastructure and not a type of data so it is handled separately. No change made.		
PacifiCorp		PacifiCorp would like to express their appreciation to the SDT for their efforts. This consolidation effort has resulted in a more streamlined approach to this set of interrelated NERC Reliability Standards. PacifiCorp would recommend that NERC

Organization	Yes or No	Question 5 Comment
		consider other sets of standards for which such a consolidation effort would be mutually beneficial to NERC and stakeholders, from both a compliance and administrative standpoint.
Response: Thank you for your support.		
Dominion		Page 1 and Page 15 of the Violation Risk Factor and Violation Severity Level Assignments document, titles reads; Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-2, TOP-003-2:, Dominion suggests changing TOP-002-2 to TOP-002-3.
Response: The suggested correction has been made.		
Pepco Holdings Inc		PHI supports the comments provided by the ISO/RTO Standards Review Committee.
ISO/RTO Standards Review Committee		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Midwest ISO, Inc.	Affirmative	Please See SRC Comments Submitted
New Brunswick System Operator	Negative	Please see comments submitted by the NPCC Reliability Standards Committee and IRC/SRC
Southwest Power Pool Reliability Standards Development Team		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
City Utilities of Springfield, Missouri	Negative	City Utilities of Springfield, Missouri supports the comments of SPP.

Organization	Yes or No	Question 5 Comment
Empire District Electric Co.	Negative	EDE agrees with the comments provided by SPP RTO
ISO New England Inc.		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Nebraska Public Power District		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Constellation Energy		The definition of Reliability Directive is contained in COM-002-3 which has not been approved at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved or change? Since the two projects appear to be on similar timelines for stakeholder approval, we suggest that the two drafting teams (Projects 2007-03 and 2006-06) coordinate presentation of the standard revisions for NERC Board approval to occur at the same time. Likewise, NERC should file both for FERC approval concurrently.
Northeast Power Coordinating Council		TOP-001-2 is referencing a NERC definition for "Reliability Directive" which is not in effect today and is listed on the Definitions of Terms Used in Standard Section on page 2. It is stated that the definition of "Reliability Directive" would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for "Reliability Directive" changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an "across the board" usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is

Organization	Yes or No	Question 5 Comment
		necessary to address an Emergency or Adverse Reliability Impacts." It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team as well.		
Southwest Power Pool Regional Entity		The standards being proposed are not sufficient to replace the requirements of the 9 standards being retired by this project. The requirements listed below are not covered by the new standards. TOP-001-1 R5. New requirement (TOP-001-2 R11) does not cover "take actions to avoid when possible or mitigate the emergency." Pre-emptive action is an important part of preventing cascading outages. The proposed TOP-001-2 R11 only deals with real time violations. The SDT is relying upon IRO-001-3 being approved in order to retire some of these requirements; however, this has not yet been passed by industry. TOP-002-2R1. If conditions change on the current day, where in the proposed standards is a new operating plan required to prepare for the next contingency or identify new SOLs? R6. Which of the proposed standards obligate the TOP to continuously plan for the next N-1 event? R13. MOD-024 and MOD-025 (which would replace this requirement) were not approved by FERC in the initial set of standards. A replacement standard MOD-025-2 has been posted for comment, but has not had an initial ballot. TOP-004-2R1. The proposed TOP-001-2, R7 and R9, only requires IROLs and certain SOLs be respected. The requirement being retired applied to all SOLs. This reduces BES reliability. R4. This covers cases where no Operational Planning Assessment is available to

Organization	Yes or No	Question 5 Comment
		ensure the system is in a safe state. The proposed TOP-002-3 does not include any requirement about when a new study is needed. TOP-006-2R5., R6., R7. The SDT is relying on the certification process to justify the retirement of these requirements. However, the Certification Process only looks at approved applicable Reliability Standards. If these are retired, these will no longer be reviewed by the Certification Team. TOP-008-1R2. The current language in TOP-008-1, R2 of "shall operate to prevent the likelihood that a disturbance will result in an IROL violation" is different than the proposed language of TOP-001-2, R7 and R9 "shall not operate outside the IROL (or SOL)". We recommend incorporating the "shall operate to prevent the likelihood that a disturbance will result in an IROL violation" into TOP-001-2 R7. PER-001-0R1. The existing requirement specifically places the responsibility on the personnel on shift not on the senior management. This does not appear to be covered by any other requirement. PRC-001-1 R2. The obligation to take corrective actions for protection relay or equipment failures is not covered by the proposed TOP-003-2 standard.

Response: TOP-001-1, R5: For anticipated conditions, the proposed TOP-002-3, Requirements R2 and R3 require the TOP to “develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.” The proposed TOP-001-2, Requirement R11 requires each Transmission Operator to “act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL’s Tv, or of an SOL identified in Requirement R8.” When the exceedance anticipated in the assessment of the Operational Planning Analysis in proposed TOP-002-3, Requirement R1 becomes an actual exceedance in Real-time operations, the plan that the Transmission Operator developed per proposed TOP-002-3, Requirements R2 and R3 is to be implemented. Thus, the possible appropriate action to take, according to proposed TOP-001-2, Requirement R11 is to “act or direct others to act” in accordance with the plan that addresses the exceedance. Of course, this is all accomplished in accordance with the Reliability Coordinator as per approved IRO-008-1. No change made.

IRO-001-3: The SDT understands the timing and coordination issues involved with IRO-001-3 and is working closely with Project 2006-

Organization	Yes or No	Question 5 Comment
06 in this regard. TOP-002-2, R1: TOP-002-3 uses Operational Planning Analysis which includes contingency planning. The SDT believes that this will incorporate most of the situations that will occur in real-time. If something comes along that wasn't in the plan the language doesn't preclude an entity running a new analysis. No change made. TOP-002-2, R6: Requirement R6 does not mandate continuous planning. The mapping document shows how the SDT is proposing replacing this requirement. No change made. TOP-002-2, R13: The SDT is aware of the coordination issues involved and will take appropriate actions when, and if, required to make certain that there is no reliability gap created. TOP-004-2, R1: The SDT has provided the reasoning for the handling of SOLs repeatedly over the life of the project. The majority of the industry is on board with these changes as seen in provided comments. The SDT believes that the suggested changes do not adversely affect reliability. No change made. TOP-004-2, R4: The old Requirement R4 does not say anything about a new study. The SDT believes that the mapping shown for this requirement clearly covers the situation. No change made. TOP-006-2, R5: The certification process is not necessarily restricted to existing requirements. In deleting requirements based on certification, the SDT is responding to guidance received from NERC staff which has instructed SDTs to delete requirements that can and will be shown as initial capabilities during certification. In addition, where such requirements have been deleted in this project, the mapping document always shows where other remaining requirements would be violated if the core certification requirements aren't met and maintained. Therefore, no reliability gap is created. No change made. TOP-008-1, R2: Any pre-emptive actions for IROLs are the responsibility of the Reliability Coordinator as per the approved IRO standards. No change made. PER-001-0, R1: The SDT proposed in the first posting of this project that such a requirement is no longer needed in standards as cited in the posted mapping document. No change made. PRC-001-1, R2: There is no wording here for corrective actions. That is covered in PRC-004-2a, Requirement R2. No change made.		
South Carolina Electric and Gas		There is a mistake in the mapping document for TOP-001-2 R11 as the language doesn't match the language in the Standard. There is additional language in the mapping document that states "within 30 minutes," which the standard does not,

Organization	Yes or No	Question 5 Comment
		and should not say. This occurs on page 36 for the mapping of current TOP-007 R2 to proposed TOP-001-2 R11. Additonally, SCE&G believes that it would be erroneous to remove TOP-004 R5 on the basis of the functional model. The functional model for the TOP stipulates that the TOP "is responsible for the real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably." If a situation were to arise where there was not sufficient time to contact the RC or if the RC was taking action that would put the TOP in jeopardy, SCE&G believes that the TOP has the right to separate from the Interconnection to protect the reliability of its system as is spelled out in current standard TOP-005 R5.
Response: The mapping document language was not properly updated when the requirement was changed from a 30 minute perspective to a limits perspective. However, the context hasn't changed and the SDT does believe that the suggested requirement addresses the issue. The mapping document has been cleaned up appropriately. No other change made. The SDT is not basing the deletion of this requirement solely on the Functional Model. Good operating practice would dictate such a deletion as well. The SDT believes that separation must be under the control of the Reliability Coordinator. No change made.		
Xcel Energy		There is reference in each draft standard to deleting some requirements from PRC-001 but those proposed changes are not show in any proposed drafts or implementation plans (only 1 PRC-001 requirement is listed in the implementation plan).
Response: The PRC standard was inadvertently left out of this posting but has been provided as part of the next posting. The Implementation Plan has been updated as well.		
Western Area Power Administration		TOP 1 and 2 as written are generally acceptable. TOP 3 opens doors for manipulation.

Organization	Yes or No	Question 5 Comment
Response: Without specific comments, the SDT is unable to respond.		
The Valley Group, a Nexans Company		TOP-004-2 R4:If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits, as determined by System Operating Limits or real-time measurements, have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits (SOLs or Real-Time Limits) within 30 minutes. TOP-006-2 R1.2Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources, as determined with SOLs or Real-Time Calculated limits, available for use. TOP-006-2 R2:Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real time operating capacity, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. TOP-008-1 R2:Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall operate the Bulk Electric System to the actual real-time limits (if available) or the most limiting derived parameter. TOP-008-1 R3:The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. The Transmission Operator shall review the real time status and capacity of transmission facility prior to disconnecting, if applicable. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

Organization	Yes or No	Question 5 Comment
		TOP-008-1 R4:The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation. If applicable, and prior to immediate mitigation, the Transmission Operator shall review real time status and capacity of the equipment, and based on those, made necessary adjustments.
Response: The SDT does not understand the comment which appears to be a cut and paste of some existing requirements with no suggestions. No change made.		
Ameren		We highly recommend that you do not lump requirements that include SOL with IROL. IROLs by definition should have VRFs higher than SOL. So it is not possible to properly assign the VRF consistent with the NERC VRF/VSL Guideline documents. We would suggest that the SDT could review what the FAC-003 SDT has done and then provide separate Requirements when there are known and expected VRF differences for different elements covered by a combined Requirement.
Response: In this case, the SOLs being referenced are specifically, and explicitly, identified as important to a local area. This does not equate an SOL to an IROL but does imply common handling of the VRF. No change made.		
BGE		We realize that SDT for Project 2006-06 is responsible for defining Reliability Directive; however, we would like to reiterate our position that the definition must capture the identification concept that is reflected in Requirement (R1). As a result, when Reliability Directive is used elsewhere, it would be clear that the communication must be identified as a Reliability Directive. Additionally, the currently proposed definition of Reliability Directive is also contained in COM-002-3 and IRO-001-3 which have not been approved at this time. What happens if the TOP standards are approved and the COM and IRO standards are subsequently not approved or change? The revised definition should stay with each of the 3 standards until it is in the Glossary of Terms. Since the two projects

Organization	Yes or No	Question 5 Comment
		appear to be on similar timelines for stakeholder approval, we suggest that the two drafting teams (Projects 2007-03 and 2006-06) coordinate presentation of the standard revisions for NERC Board approval to occur at the same time. Likewise, NERC should file both for FERC approval concurrently. We are voting affirmatively because we support the improvements achieved by the drafting team work so far. However, we raised remaining concerns with the standard proposal on the comment form submitted on behalf of BGE. We expect the drafting team to continue to make clarifying changes until the end of this stakeholder process. The greater the clarity in the final product, the less risk of contradictory perspectives on compliance.
Response: Your suggestion has been forwarded to Project 2006-06. The SDT is coordinating activities with Project 2006-06 in this regard. The SDT will continue to work to refine the standards until the end of the stakeholder process.		

END OF REPORT