Consideration of Comments

Project Name:	2016-01 Modifications to TOP and IRO Standards | IRO-002-5 and TOP-001-4
Comment Period Start Date:	6/20/2016
Comment Period End Date:	8/3/2016
Associated Ballots:	2016-01 Modifications to TOP and IRO Standards IRO-002-5 IN 1 ST 2016-01 Modifications to TOP and IRO Standards TOP-001-4 IN 1 ST

There were 58 sets of responses, including comments from approximately 156 different people from approximately 76 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

The Project 2016-01 Standards Drafting Team (SDT) appreciates the constructive feedback from stakeholders. As a result of comments received, the SDT made improvements to proposed IRO-002-5 and TOP-001-4 and implementation plan to incorporate stakeholder recommendations. Although IRO-002-5 received enough stakeholder support to proceed to final ballot, the SDT has made revisions in the second draft of the standard to address stakeholder concerns and maintain consistency with similar requirements in TOP-001-4. Accordingly, both standards are being posted for 45-day formal comment period and will undergo a 10-day additional ballot at the end of the comment period.

Section 4.12 of the NERC Standard Processes Manual indicates that the SDT is not required to respond in writing to comments from the previous posting when it has identified the need to make significant changes to the standard, however the SDT is providing summary responses to the comments received in order to facilitate stakeholder understanding of the changes made for the second posting.

The following is an overview of changes made by the SDT. Specific comments and revisions are discussed more fully in the summary consideration that follows.

- **Requirement for Transmission Operator (TOP) monitoring of non-Bulk Electric System (BES) facilities needed for determining SOL Exceedances (Proposed TOP-001-4 Requirement R10).** The SDT has revised the rationale section in response to stakeholder comments. The rationale describes some methods for determining non-BES facilities that should be monitored by the TOP for determining SOL exceedances. The rationale also emphasizes that the non-BES facilities that are required to be monitored are those that are needed for determining SOL exceedances.

- **Requirements for redundancy and diverse routing of data exchange capabilities used by Reliability Coordinators (RC), Balancing Authorities (BAs), and TOPs (Proposed IRO-002-5 Requirement R2 and Proposed TOP-001-4 Requirements R20 and R23).** The SDT has revised the requirements for redundant and diversely routed data exchange capabilities to clarify that these requirements apply to the applicable entity's primary Control Center. The SDT also provided additional details in the rationale section to clarify what is meant by *redundant and diversely routed data exchange infrastructure within the entity's primary Control Center*:

- **Requirements for testing of data exchange capabilities (Proposed IRO-002-5 Requirement R3 and Proposed TOP-001-4 Requirements R21 and R24).** The SDT has modified the periodicity required for testing the redundant functionality of data exchange capabilities to quarterly (within 90 calendar days from the previous test). The SDT has also clarified in the requirements that the testing is for primary Control Centers consistent with the directive in Order No. 817. Finally, the SDT modified the associated measures to include use of evidence from an actual event that demonstrated the redundant functionality for satisfying the testing requirement.

Questions

1. The SDT has developed TOP-001-4 Requirement R10 to address directives for TOP monitoring of non-BES facilities necessary for reliability. Do you agree with the proposed requirement? If you do not agree, or if you agree but have comments or suggestions for the proposed requirement provide your recommendation and explanation.
2. The SDT has developed IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23 to address directives for redundancy and diverse routing of RC, TOP, and BA data exchange capabilities. Do you agree with the proposed requirements? If you do not agree, or if you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.
3. The SDT has developed IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24 to address directives for testing redundancy of data exchange capabilities used in RC, TOP, and BA control centers. Do you agree with the proposed requirements? If you do not agree, or if you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.
4. Do you agree with the Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.
5. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs provide your recommendation and explanation.
6. Provide any additional comments for the SDT to consider, if desired.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Independent Electricity System Operator	Ben Li	2	NPCC	ISO/RTO Council Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Greg Campoli	NYISO	2	NPCC
					Ali Miremadi	CAISO	2	WECC
					Ben Li	IESO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Terry Bilke	MISO	2	MRO
					Liz Axson	ERCOT	2	Texas RE
Chris Gowder	Chris Gowder		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utility Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Don Cuevas	Beaches Energy Services	1	FRCC
					Stan Rzad	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steve Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Mark Brown	City of Winter Park	4	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	9	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
ACES Power Marketing	Colleen Campbell	6	NA - Not Applicable	ACES Standards Collaborators	Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE
					Greg Froehling	Rayburn Country Electric Cooperative	3	SPP RE
					Bill Hutchinson	Southern Illinois Power Cooperative	1	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC

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					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Paul Mehlhaff	Sunflower Electric Power Corporation	1	SPP RE
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	3,4,5,6	MRO
					Chuck Wicklund	Otter Tail Power Company	1,3,5	MRO
					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Jodi Jenson	Western Area Power Administration	1,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Shannon Weaver	Midwest ISO Inc.	2	MRO
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Brad Perrett	Minnesota Power	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Terry Harbour	MidAmerican Energy Company	1,3,5,6	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,4,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Dana Wheelock	Seattle City Light	3	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,3,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Con Ed - Consolidated Edison Co. of New York	Kelly Silver	1	NPCC	Con Edison	Kelly Silver	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange and Rockland Utilities	NA - Not Applicable	NPCC
Lower Colorado River Authority	Michael Shaw	6		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						and Energy Marketing		
Dominion - Dominion Resources, Inc.	Randi Heise	5		Dominion - RCS	Larry Nash	Dominion Virginia Power	1	SERC
					Louis Slade	Dominion Resources, Inc.	6	SERC
					Connie Lowe	Dominion Resources, Inc.	3	RF
					Randi Heise	Dominion Resources, Inc,	5	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Mark J. Kenny	Eversource Energy	1	NPCC
					Gregory A. Campoli	NY-ISO	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Michael Forte	Con-Edison	1	NPCC
					Kelly Silver	Con-Edison	3	NPCC
					Peter Yost	Con-Edison	4	NPCC
					Sean Bodkin	Dominion	4	NPCC
					Silvia Parada Mitchell	NextEra Energy	4	NPCC
					Brian O'Boyle	Con-Edison	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					John Allen	City of Utilities of Springfield, MO	1,4	SPP RE
					Kevin Giles	Westar Energy	1,3,5,6	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Robert Gray	Board of Public Utilities, KS	NA - Not Applicable	NA - Not Applicable
					Donald Schmitt	Nebraska Public Power District	1,3,5	MRO
					Jerry McVey	Sunflower Electric Power Corporation	1	SPP RE
Santee Cooper	Shawn Abrams	1		Santee Cooper	Shawn Abrams	Santee Cooper	1	SERC
					James Poston	Santee Cooper	3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Michael Brown	Santee Cooper	6	SERC
					Tommy Curtis	Santee Cooper	5	SERC
Colorado Springs Utilities	Shawna Speer	1		Colorado Springs Utilities	Shawna Speer	Colorado Springs Utilities	1	WECC
					Shannon Fair	Colorado Springs Utilities	6	WECC
					Charles Morgan	Colorado Springs Utilities	3	WECC
					Kaleb Brimhall	Colorado Springs Utilities	5	WECC

1. ***The SDT has developed TOP-001-4 Requirement R10 to address directives for TOP monitoring of non-BES facilities necessary for reliability. Do you agree with the proposed requirement? If you do not agree, or if you agree but have comments or suggestions for the proposed requirement provide your recommendation and explanation.***

Summary Consideration. The SDT thanks all commenters. The SDT is not proposing any changes to Requirement R10 in the current draft, but has revised the Rationale section in response to stakeholder comments. The SDT believes proposed Requirement R10 addresses the reliability objectives outlined in the project Standards Authorization Request (SAR) and the directive in FERC Order No. 817.

Specific comments and SDT responses are provided below:

- **Some commenters stated that it is unclear which non-BES facilities need to be monitored. Commenters stated that the proposed wording "identified as necessary" is ambiguous.** TOPs perform various analyses and studies that can lead to the identification of non-BES elements that need to be monitored for determining SOL exceedances. The proposed requirement provides flexibility for TOPs to use any selected means and still accomplish the reliability objective. The rationale has been revised to describe some methods for determining non-BES facilities that should be monitored for determining SOL exceedances. Other mechanisms may also be appropriate. The Rationale and draft Reliability Standard Audit Worksheet now include the following:

  The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances within its TOP Area. TOPs perform various analyses and studies as part of their functional obligations that could lead to identification of non-BES facilities that should be monitored for determining SOL exceedances. Examples include:
  - *OPA;*
  - *Real-time Assessments (RTA);*
  - *Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and*
  - *Analysis which may be specified in the RC's outage coordination process that leads to the identification of a non-BES facility that should be temporarily monitored for determining SOL exceedances.*

- **Commenters disagreed with the proposed revision to Requirement R10 because the BES definition and exception process would handle identifying all facilities that need to be monitored. A commenter stated that a non-BES facility identified as necessary for monitoring becomes a BES facility for the purposes of CIP-002-5.1. A commenter stated that the proposed requirement did not sufficiently benefit reliability.** The SDT agrees that analyses performed in support of BES inclusions can identify some non-BES facilities that should be monitored for reliability and has included this example in the proposed Rationale. The SDT believes that when a TOP identifies facilities that should be monitored for determining SOL exceedances and the facilities are being processed for BES inclusion, they should be monitored. The SDT does not agree that the proposed changes to Requirement R10 affect the applicability of facilities within the CIP-002-5.1 standards. The SDT believes the proposed requirement benefits reliability and addresses thedirective contained in Order No. 817 by ensuring all facilities (i.e., BES and non-BES) that can adversely impact reliability are monitored.

- **A commenter stated that TOPs can have their own methodology, rather than Operational Planning Analysis (OPA), for identifying which non-BES facilities should be monitored for determining SOL exceedances. Commenters recommended prescribing a rigorous process or more specific criteria for entities to use in determining which non-BES facilities should be monitored for determining SOL exceedances.** The proposed requirement provides necessary flexibility for identifying the non-BES facilities that should be monitored for determining SOL exceedances. In the Rationale, OPA is listed as an example of a type of analysis that could lead a TOP to discovering a non-BES facility that should be monitored for determining SOL exceedances. The SDT does not believe a prescriptive requirement will benefit reliability. The requirement and Rationale support flexibility for an entity to develop its own methodology or criteria that are appropriate for its system and operating practices.

- **A commenter expressed concern with the proposed changes to Requirement R10 because requirements do not exist for non-registered entities to provide data.** The SDT believes that some TOPs may need to use mechanisms for obtaining data on non-BES facilities in addition to the obligations under TOP-003-3. For example, a TOP and a non-registered entity could enter into a data exchange agreement to obtain necessary operating information, or the TOP may identify a requirement in the interconnection agreement that supports obtaining the necessary operating information.

- **A commenter stated that the proposed changes to Requirement R10 could not be considered until other standards projects which could potentially affect the SOL definition is concluded.** Project 2016-01 is proceeding to meet regulatory deadlines established in Order No. 817.

- **Commenters suggested wording changes for the proposed requirements.** The SDT considered all suggestions and determined that the proposed changes did not provide additional clarity.

Thomas Foltz – AEP - 5	
Answer	No
Document Name	
Comment	

AEP recognizes FERC's concerns regarding identification of non-BES facilities, however, there would be far more flux involved in their identification and real-time monitoring (as suggested by the SAR) than may be widely understood or appreciated. This subset of non-BES facilities would change quite frequently, and creating obligations to govern such frequently changing identification and real-time monitoring would likely require much effort, with little to no improvement in reliability. Rather than developing additional requirements which would not likely be beneficial, we continue to believe a more prudent approach would be to focus on the desired end state itself. We believe the argument can still be made that our existing obligations, when considered as a whole, could collectively appease FERC's concerns.	
Likes 0	
Dislikes 0	
Justin Wilderness - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	
What defines the list of facilities that are required to be telemetered and used ?	
Likes 0	
Dislikes 0	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	No
Document Name	
Comment	

There is already a mechnism via the BESnet tool to submit non-BES elements for inclusion. For elements that have a long term impact on the Reliability of the BES, this is the correct way to address it, not blur the lines between BES and non-BES without far more detailed guidelines to protect entities from well meaning auditors. Entities already have an obligation to respond to requests from the RC/PC/BA, this new requirement will not add any reliability that isn't already addressed.	
Likes 0	
Dislikes 0	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	No
Document Name	
Comment	
NERC already makes provision for the modification of BES Facilities through the Inclusions and Exclusions spelled out in the NERC definition of Bulk Electric System therefore Vectren believes the Requirements R10.3 and R10.6 are redundant and unnecessary. An entity may choose to monitor a non-BES facility but it shouldn't fall under a NERC requirement if it wasn't previously identified in the BES Inclusion.	
Likes 0	
Dislikes 0	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
RF offers the following comment and modification for the SDTs consideration.	

1. Requirement R10 i. The term “identified as necessary” is ambiguous and can lead to confusion in industry. For example, as written, there is no requirement for the TOP to identify “non-BES facilities” that are “necessary”. In the rational section, it alludes to the fact that the TOP identifies these “necessary facilities” by performing planning and operating studies such as the Operational Planning Analysis required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. RF suggests replacing all the Requirement R10 sub-part language containing the phrase “identified as necessary” with the following language “identified as a result of performing planning and operating studies required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1”.	
Likes 0	
Dislikes 0	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC is concerned regarding requirements 10.3 and 10.6 as there is a perceived disconnect between the TOP requirement to monitor without a corresponding requirement for non-registered entities to provide requested data needed for monitoring. The standard as written requires the TOP to monitor non-BES facilities within its Transmission Operator Area. In one specific case in ATC’s system, the entity who owns the facilities and thus manages the model and real time data is not a registered TOP, BA, GO, GOP, LSE, TO, or DP so they have no compliance obligation to provide the data. As good utility practice we believe they should provide the data but that’s no guarantee that they will. If ATC, as the TOP, does not have the correct operating parameters, whether impedances, charging values or ratings, or we do not have the correct real-time telemetry, we cannot properly monitor the operating state of their facilities and the resulting impacts on our system. If we cannot monitor, we cannot be compliant. Consider amending R10.3 to read as follows:	

Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator. In those cases where sufficient modeling and real time data is not available from the facility owner and the facility owner is not required to provide said data then monitoring is not feasible and not required.	
Likes 0	
Dislikes 0	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Part 10.3 leave the question as to who shall determine the necessity to monitor non-BES facilities. Which Transmission Operator? SRP recommends address this ambiguity by adjusting the verbiage to be "Monitor non-BES facilities within its Transmission Operator Area it has identified as necessary." SRP recommends similar adjustments to parts 10.4, 10.5, and 10.6 for consistency.	
Likes 0	
Dislikes 0	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
There seems to be some ambiguity as to why a TOP would monitor non-BES facilities necessary for reliability versus including the less than 100 kV element as a BES element through the exception process. If the < 100 kV facility has a significant impact on the BES system it seems logical that the non-BES facility would be added to the list of BES elements for the TOP. The only reason we can surmise that a <100 kV facility would be monitored instead of added as an exception would be if the facility was outside of the TOP area, such as a	

generator on the distribution system or a neighboring TOP line that has a significant impact on the TOPs system. For these examples, the TOP would not have the ability to designate the <100 kV facility as BES and therefore they would only be able to monitor it in a similar manner to BES facilities. We recommend the drafting team revise the language in order to remove some ambiguity as to when a non-BES would be monitored versus added as a BES element.	
Likes 0	
Dislikes 0	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE is concerned there is no guidance provided for the phrase "identified as necessary" (in TOP-001-4, parts 10.3-10.6) which will result in inconsistencies by Transmission Operators in the identification of data needed for determining SOL exceedances. Texas RE recommends setting thresholds, such as an outage distribution factor for including non-BES facilities or facilities outside the TOP Area. A threshold for distribution factors for contingency outages would create a concrete target for registered entities. Texas RE is also concerned there is no guidance for the terms "neighboring" and "adjacent", as well as no requirements for TOPs who may designate something within its own TOP Area that may affect a neighboring/adjacent TOP's Area SOL exceedance(s) (i.e., no communication requirement, no coordination requirement).	
Likes 0	
Dislikes 0	
David Bueche - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	

Comment	
CenterPoint Energy does not agree with the language in R10.3 and recommends it be modified to more closely resemble language used in R10.6. Strictly monitoring non-BES facilities within a TOP Area will not assist in determining SOL exceedences. In order to determine SOL exceedences, information from non-BES facilities must be utilized to determine how non-BES facilities will affect SOLs. CenterPoint Energy recommends the following language: **R10.3 Utilize status, voltages, and flow data for non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator.**	
Likes 0	
Dislikes 0	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We believe the SDT has significantly deviated from the expectations identified within the FERC directive, which asks for the real-time monitoring of non-BES facilities necessary to determine SOL exceedances. The guidance provided by the SDT references Operational Planning Analyses and various other requirements that are independent of this standard. The SDT has provided no defined criteria for determining what is “necessary,” leaving its interpretation subjective by an Auditor. We believe it should be up to the TOP to develop its own methodology to determine what is necessary, including which non-BES facilities should be monitored and included in the pre-Contingency analyses of its Real-time Assessments; this should be reflective within the RSAW. Hence, we ask the SDT to consider using this alternative language in its place: “Monitor non-BES facilities located within its Transmission Operator Area necessary to complete pre-Contingency analyses for Real-time Assessments.”	
Likes 0	
Dislikes 0	

Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
1. The NERC Standard Drafting Team (SDT) has not completed work on the definition of the System Operating Limit (SOL) which is the cornerstone for the TOP-001. The industry has to have clear definition of SOL in order to be able to comply with the TOP-001. The industry needs the SOL definition from the SDT and before voting for TOP-001 and the additional impact of including non-BES elements. 2. The criteria for monitoring non-BES facilities within the TOP area is defined vaguely by using wording "**identified as necessary by the Transmission Operator**" . This vague definition opens a large space for interpretations and ambiguity. The criteria for monitoring non-BES facilities needs to be clearly defined. It may be inappropriate to apply a BES process to a non-BES facility, or at a minimum NERC standards need to include corresponding language for non-BES facilities that are being monitored in operations, otherwise why have the BES exception process of including non-traditional BES facilities as BES facilities.	
Likes 0	
Dislikes 0	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
TOPs currently decide which Facilities need monitoring. Introducing the language "as necessary" needs to be defined if it is a change from current practice.	
Likes 0	
Dislikes 0	

Jeffrey Watkins - On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5;	
Answer	No
Document Name	
Comment	
NVE has concerns that the wording of the phrase "identified as necessary by the Transmission Operator" is too vague. There is no requirement for the TOP to identify non-BES facilities as necessary or criteria for determining which non-BES facilities should be studied. The rationale section mentions that these facilities could be identified by planning and operational studies such as the Operational Planning Analysis required by TOP-002-4 Requirement 1. Based on this requirement, NVE is also concerned that the subset of non-BES facilities could change quite frequently based on the Operational Planning Analysis, creating much effort to identify and monitor frequently changing non-BES facilities. NVE feels that some guidance should be given to help identify which non-BES facilities should be monitored.	
Likes 0	
Dislikes 0	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR agrees with most of the proposed requirement in R10. However for those requirements with the "…identified as necessary by the Transmission Operator…" consider altering the language to "…identified as necessary by the Transmission Operator to determine System Operating Limit (SOL) exceedances…". While it might be clear when looking at the main and sub-requirement together, the sub-requirement itself is less clear and separated from the main requirement by other sub-requirments that do not have an "… as necessary…" qualifier. The proposed language change clarifies to what extent is it considered necessary and reminders the reader of the purpose of the main requirement.	
Likes 0	
Dislikes 0	

Douglas Webb - On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1;	
Answer	No
Document Name	
Comment	
Under the plain reading of TOP-001-4 R10, when a non-BES Facility that adversely impacts reliability is identified, it essentially becomes a BES Facility ("Converted non-BES Facility", are term for purposes of these comments). As a Converted non-BES Facility, it falls within the applicability of CIP-002-5.1 (See Applicability Sec. 4.2.2.). The concern is R10 has the effect of drawing the Facility into CIP-002, which does not provide guidance as how Converted non-BES Facilities are to be characterized—High, Medium, Low Impact Cyber Assets. While an entity may be able to "fit" the Converted non-BES Facility within CIP-002 criteria to assign an impact rating, it is not ideal. The scenario muddles an entity's compliance obligation under both Standards.	

Additionally, CIP-002-5.1 Applicability creates double impact criteria—where a cyber asset affects a facility and that facility affects the reliable operation of the BES. Under Project 2016-02, Modifications to CIP Standards, the SDT will address and clarify the double impact criteria issue which, in turn, will impact how Converted non-BES Facilities will be characterized. While we can accept the TOP in R10 making the determinations and identifications, it is our belief that the Standard would better align with the objectives of other Standards by having the RC designate a non-BES facility with a capability to adversely impact the BES; pulling it into scope; and, the RC having a process to bring that facility into scope for Real Time Monitoring and Analysis. We would respectfully ask the SDT consider the compliance implications under CIP-002, and other applicable Standards, when identifying a non-BES Facility as adversely impacting reliability, converting it to a BES Facility.	
Likes 0	
Dislikes 0	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
How do you have an effective date of a procedure prior to the implementation of the system change?	
Likes 0	
Dislikes 0	
Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

There are 2 typos: • M20 (…)in order to perform its Real-time monitoring and Real-time Assessments as specified in the requirement • M23 (…) in order to perform its Real-time monitoring and analysis functions as specified in the requirement. **We suggest that when you provide the rationale to TOP-001-3 at the end of the standard, you indicate the correspondence with the new (TOP-001-4) numbering of the requirements. Thus, the last paragraph would read:** Rationale for Requirements R19 and R20 (Correspond to R19, R20, R22 and R23 in TOP-001-4)	
Likes 0	
Dislikes 0	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	
Comment	
The phrase "...identified as necessary by the Transmission Operator" leaves a large amount of latitude in determining whether non-BES facilities should be identified. More specificity on this point would improve clarity and reduce the reisk of noncompliance by TOPs.	
Likes 0	
Dislikes 0	
sean erickson - Western Area Power Administration - 1	

Answer	Yes
Document Name	
Comment	
WAPA agrees with monitoring certain identified Non-BES facilities per engineering judgement and neighbor input (especially under prior outage conditions) with the caveat that this could greatly increase the scope and workload of the TOPs and RC.	
Likes 0	
Dislikes 0	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
We request the SDT to provide some rationale or guidance to what is expected of a TOP in 'identifying non-BES facilities' as being necessary. What is considered a sufficient identification process? We are not looking for a prescriptive requirement. We just request guidance. Any revisions to the rationale should also be reflected in the 'Note to Auditor' section(s) of the RSAWs.	
Likes 0	
Dislikes 0	
Stephanie Burns - On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1;	
Answer	Yes
Document Name	
Comment	

ITC concurs with the comments and position provided by SPP.	
Likes 0	
Dislikes 0	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
We understand that these changes are to address a FERC Directive. This is basically a fill in the blank requirement. However, clarification of “as necessary” would be appreciated.	
Likes 0	
Dislikes 0	
Emily Rousseau – MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
We understand that these changes are to address a FERC Directive. This is basically a fill in the blank requirement.	
Likes 0	
Dislikes 0	

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	
Document Name	
Comment	
We understand that these changes are in direct response to a FERC Directive and neither agree nor disagree.	
Likes 0	
Dislikes 0	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC Standards Review Committee (SRC). We understand that these changes are in direct response to a FERC Directive and neither agree nor disagree.	
Likes 0	
Dislikes 0	
Oshani Pathirane - On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3;	
Answer	
Document Name	
Comment	

TOP-001-4 R10 is not applicable to Hydro One Networks Inc.	
Likes 0	
Dislikes 0	
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
no comments	
Likes 0	
Dislikes 0	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Joshua Smith - On Behalf of: Lee Maurer, Oncor Electric Delivery, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
David Kiguel - 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Chris Gowder - On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; , Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Matthew Beilfuss - WEC Energy Group, Inc. - 1,3,4,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Stanley Beasley - On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Stanley Beasley - On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Chris Scanlon – Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	
Document Name	
Comment	
No opinion	
Likes 0	
Dislikes 0	

2. The SDT has developed IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23 to address directives for redundancy and diverse routing of RC, TOP, and BA data exchange capabilities. Do you agree with the proposed requirements? If you do not agree, or if you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.

Summary Consideration. The SDT thanks all commenters. In response to stakeholder comments, the SDT has revised the requirements for redundant and diversely routed data exchange capabilities to clarify that these requirements apply to the applicable entity's primary Control Center. The SDT also provided additional details in the Rationale section as shown below to clarify what is meant by *redundant and diversely routed data exchange infrastructure within the entity's primary Control Center (IRO-002-5 Rationale shown below)*:

> *Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g. switches, routers, file servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Reliability Coordinator's (RC) Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data to System Operators. Requirement R2 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the RC's primary Control Center.*

Other specific comments and SDT responses are provided below:

- **Commenters expressed concerns about perceived obligations for redundancy and diverse routing during planned or unplanned outages.** Proposed IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23 specify capabilities and infrastructure that will preclude single points of failure in the applicable entity's primary Control Center. The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. The proposed requirements do not specify, and should not be interpreted to require, additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components. The SDT has indicated this clarification in the Rationale box. Furthermore, the SDT believes the proposed measures associated with the requirements add clarity by listing appropriate evidence for assessing the data exchange capabilities used by the applicable entity (e.g. system diagrams, system specifications, or other documentation that lists its data exchange capabilities including redundant and diversely routed data exchange infrastructure).

- **Commenters recommended defining *Redundancy and Diverse Routing; other* commenters sought clarification as to what infrastructure is covered in the proposed requirement, such as whether dual data connection links were required to each entity.** The SDT confirms that the proposed requirements apply to infrastructure within the primary Control Center, and do not require dual, external data links to each entity exchanging data. The revised Rationale provides further clarity.

- **Commenters suggested moving the proposed requirements to TOP-003-3 or a separate COM standard.** The SDT believes the directive for redundancy and diverse routing of data exchange capabilities should be addressed by modifying the existing Requirements for data exchange capabilities contained in IRO-002 and TOP-001.

- **A commenter recommended modifying the proposed requirement to allow for redundancy that is accessible from the applicable entity's control center.** The intent of the proposed requirements is to ensure that single points of failure do not exist within the applicable entity's primary Control Center data exchange infrastructure. The SDT agrees that redundancy exists external to the primary Control Center, however the proposed requirement is aimed at providing reliability benefit from redundancy within the primary Control Center. The SDT notes that the definition of Control Center includes supporting data centers, making these facilities internal to the control center. Accordingly, the SDT does not believe the commenter's proposed revision addresses the intended objective.

- **A commenter expressed concern that the proposed requirement for redundant and diverse routing within the entity's Control Center did not address the regulatory directive. The commenter stated that, unlike requirements for redundant voice communications capabilities, the proposed requirements in IRO-002 and TOP-001 do not address external communication links.** The SDT developed the proposed requirements to satisfy the directive and be consistent with the functional model and applicable entity's jurisdiction. Although FERC cited the COM standards in explaining the importance of providing for redundancy in data exchange capabilities, they did not prescribe a specific approach to achieving the reliability objective. The SDT does not believe that the same approach taken for redundancy in voice communications will necessarily be effective or practical for data exchange which must support a large number of data points and update rates necessary for Real-time situational awareness.

- **An entity recommended deleting Requirement R6 in proposed IRO-002-5.** Requirement R6 specifies various capabilities for the Reliability Coordinator's monitoring system which are not addressed by the proposed requirements for redundant and diversely routed data exchange infrastructure. The monitoring systems that are covered under Requirement R6 address the situational awareness capability used by System Operators, while the data exchange capabilities addressed in Requirement R2 provide the data that feeds into these monitoring systems. Therefore, the SDT does not agree that Requirement R6 can be removed without lowering the level of reliability required by the approved standard.

- **A commenter did not support the proposed requirements because approved EOP-008 provides redundancy by specifying requirements for backup control centers.** The SDT notes that the objective outlined in the project SAR and Order No. 817 is independent of EOP-008 (see Order No. 817 P 48).
- **Commenters recommended removing *diversely routed* from the proposed requirements.** The SDT is addressing regulatory directives for requiring redundant and diversely routed data exchange capabilities; the Rationale for the proposed requirements explains that the characteristics of redundant and diversely routed data exchange capabilities preclude single points of failure in the entities primary Control Center from rendering the data exchange capabilities inoperable.

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	

While PNMR agrees with the intent of the SDT for R20 and R23, the language needs more specificity. First, if the standard is to only apply to the primary Control Center then replace the language "…within the [Transmission Operator's | Balancing Authority's] Control Center…" with the following language "…within the primary Control Center of a [Transmission Operator | Balancing Authority] …." If the standard is to apply to any Control Center either primary or backup then replace the word "primary" is the suggest text with "any." In addition consider further scoping "…redundant and diversely routed data exchange infrastructure…" to include where it starts and where it ends. Does it start at the data exchange device (e.g. ICCP server, mailbox RTU) within the Control Center? Or does it start from where those devices get their data, typically an EMS or SCADA server? Or does it start from the collection of field telemetry data and thus redundant and diversely routed include the data exchange infrastructure used for field telemetry? If a beginning is not defined then it will make the standard difficult to consistently audit from Region to Region. In addition an end needs to be defined. This could be the point where the data exchange capabilities leave the Control Center. For Telco circuits this point could be defined as the demarcation (aka demarc) for the circuit.

Likes 0	
Dislikes 0	

Jeffrey Watkins - On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5;	
Answer	No
Document Name	
Comment	
NVE has concerns that the language in these requirements are too vague and that the scope of equipment that would be required to have diverse and redundant routing is not clearly defined. NVE recommends guidelines or examples perhaps in the “Guidelines or Technical Basis’ section on what equipment would be expected to be diverse and redundant. NVE also requests that clarification is given as to whether the diverse and redundant routing applies equally at the Primary and Backup Control Centers.	
Likes 0	
Dislikes 0	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
The requirements for redundancy and diverse routing of data exchange capabilities used by RC, TOP, and BA are vague and not sufficiently developed. This will lead to unnecessary standard violations as both regulator and the industry learn by trial and error what is appropriate and what isn't. At a minimum, information contained in the proposed rationale needs to be incroporated into the actual requirement as FERC has ruled that guidance (such as the rationale) cannot change the scope or intent of a requirement. I suggest at a minimum the SDT define specific important equipment and include rationale wording such as *Requirement R2 does not require automatic or instantaneous fail-over of data exchange capabilities and infrastructure that is not within the RC’s Control Center is not addressed by this requirement.*	
Likes 0	
Dislikes 0	

Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	

The requirement needs to be reworded to indicate it is a Transmission Operator and Balancing Authority's primary Control Centers. Suggested wording "Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, ...".

On the NERC webex for this project, it was stated the intent was not to have 2 telecom rooms in a control center to achieve redundancy. However, in reading the requirement this is not completely clear with the words "within the Transmission Operator's Control Center". Suggest that the SDT have some guidelines and technical basis included in the standard to provide guidance to the industry on what is required to achieve redundany and diversely routed data exchange.

Likes 0	
Dislikes 0	

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

(1)   We ask the SDT to clarify the criteria around Transmission Operator data exchange, particularly for the performance of Real-time monitoring and Real-time Assessments. We also suggest clarifying whether the loss of redundancy (i.e. loss of a single component within the Control Center infrastructure) could constitute a violation of TOP-001-4 R20. This is especially of concern when infrastructure replacement parts may take an extended time to procure, leaving a gap in a redundant network. To address this, we suggest rephrasing

the requirement to align with the format used in COM-001, such as "Each TOP shall have data exchange capabilities with the following entities, unless the TOP detects a failure of its data exchange capabilities, in which case [another requirement] shall apply." (2) We believe the Rationale section needs to clarify the meaning of "redundant and diversely routed," and that it does not apply to dual data connection links to each entity. Many entities utilize the infrastructure owned and operated by their RCs to obtain information regarding their neighboring entities. These entities would incur a significant financial burden for installation and maintenance costs associated with these additional data links. Moreover, we have concerns that network performance would be affected with the addition of these redundant links too.	
Likes 0	
Dislikes 0	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	
Matthew Beilfuss - WEC Energy Group, Inc. - 1,3,4,6 - MRO,RF	
Answer	No
Document Name	
Comment	
The proposed TOP-001-4 requirements (R22, R23, and R24) would better fit in TOP-003-Operational Reliability Data.	

TOP-003-3, "**R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring" is more closely linked with the requirement proposed in TOP-001-4 R23.	
Likes 0	
Dislikes 0	
David Bueche - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy does not agree with the language in R20. Specifically, CenterPoint Energy believes options for redundancy and diverse routing of data exchange capabilities could exist outside of the Transmission Operator's Primary Control Center, and therefore, infrastructure within the TOP's Primary Control Center may not be necessary. While FERC Order 817, paragraph 47 explains that the redundancy described with Interpersonal Communications and Alternative Interpersonal Communications in COM-001-2 are not to rely on EOP-008: CenterPoint Energy does not agree this is a direct correlation to data exchange capabilities. For example, a situation could exist where remote infrastructure for data exchange capabilities can communicate and provide redundancy to a Transmission Operator Control Center where as redundant hardware has to be present at the Transmission Operator Control Center to achieve Alternate Interpersonal Communications. CenterPoint Energy suggests the following language:

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure accessible from or within the Transmission Operator's Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. [Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange accessible from or utilizing infrastructure within the Transmission Operator's Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. [Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]

Likes 0	

Dislikes 0	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE appreciates the efforts of the Standard Drafting Team to address the various FERC directives set forth in Order No. 817. However, Texas RE is concerned that the proposed requirement implementing FERC's directive "that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing" is overly narrow. (p. 34, ¶47). In particular, the current draft of IRO-2-5 R2 applicable to Reliability Coordinators (RCs) and TOP-001-4 R20 applicable to Transmission Operators (TOPs) specified that these functions shall have redundant and diversely routed data exchange infrastructure "within the [RC's and TOP's] Control Center."

However, the FERC directive does not contain language explicitly limiting data redundancy and diverse routing capability solely to infrastructure within an applicable entity's Control Center. Rather, FERC Order No. 817 contemplates an approach that is designed to ensure that no one event can eliminate an entity's data exchange capability. For instance, FERC drew a clear analogy between the redundancy requirements for voice communications under the COM standards and the data communication redundancy and diverse routing requirements at issue here. FERC specifically noted that "[r]edundancy for data communications is no less important than the redundancy explicitly required in the COM standards for voice communication." (p. 35, ¶48). This analogy illuminates the Control Center issue. In particular, the touchstone of the diverse routing and redundancy requirements in the COM standards is the existence of two separate and independent means for voice communication. As an example, entities may employ landline and satellite phones to satisfy the COM standards. The diverse routing and redundancy inherent in this approach in essence requires two distinct and independent events to eliminate voice communications capability. That is, the loss of phone service and the loss of satellite communications.

In contrast with this application of diverse routing and redundancy in the voice communication context, it is possible to read the IRO/TOP requirements, as currently drafted, as permitting registered entities to satisfy the redundant and diversely routed data communications requirements within a single Control Center. For example, one could argue that the data communications requirements as permit two servers served by separate cables within the Control Center, but linked to a common network point outside of the Control Center as both redundant and diversely routed within the Control Center. In such circumstances, a single event could eliminate data communications

capabilities. This is in stark contrast to the layered protections created through the COM standards for voice communications and appears inconsistent with the intent underpinning the FERC directive. Texas RE is aware of the concern that Registered Entities have regarding being held responsible for data network architecture that is outside their facilities and beyond their control. However, if the SDT wishes to address this concern by retaining the Control Center concept, Texas RE recommends at least ensuring that registered entities satisfy data communications redundancy and diverse routing requirements by using separate and independent data communications facilities located at distinct Control Centers.	
Likes 0	
Dislikes 0	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy requests clarification, and further information from the drafting team on the specifics of carrying out compliance with these requirements. We suggest that a definition for redundancy and diverse routing would be helpful in aiding the industry in achieving compliance. Currently, it is unclear if the requirements call for an entity to have physically redundant hardware, redundant cabling and path, or does each entity need to establish its own definition for redundancy and diverse routing. Also, we think clarity would be improved by adding more information regarding the data exchange infrastructure aspects of the requirements and how redundancy and diversity would support the data exchange infrastructure. Ultimately, Duke Energy believes that an industry accepted definition of redundancy and diverse routing would improve understanding with the requirements, and aid entities in their implementation of said requirements. Also, we request more information from the drafting team regarding whether the TOP area is included in the expectations outlined in R20. The requirement states that Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure with entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments.	
Likes 0	

Dislikes 0	
Chris Gowder - On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; , Group Name FMPA	
Answer	No
Document Name	
Comment	
From other comments, it seems there is stakeholder confusion about what exactly “diversely routed” means and what is expected of the applicable entities. FERC acknowledged the ambiguity in their NOPR proposing to approve the revisions to the TOP and IRO standards, and seems to favor the approach taken in developing COM-001-2 to resolve the confusion. From Paragraph 73. “…it is not clear whether redundancy and diverse routing of data exchange capabilities (**or an equally effective alternative that eliminates the ambiguity of “redundancy” and “diversely routed”**) are adequately addressed in proposed Reliability Standards TOP-001-3 and IRO-002-4 for the reliability coordinator, transmission operator, and balancing authority.” FMPA believes clarity is needed either in the requirements themselves or in a defined term so that applicable entities know exactly what is expected.	
Likes 0	
Dislikes 0	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	

Comment	
The standard requirements say that the RC, TOp and BA must have redundant and diversely routed data exchange infrastructure "within the control center." The standard seems to mean that as soon as the data path enters the walls of the control center building then it must be on fully redundant and diversely routed path. If data is received from individual RTUs from the TOP, each of those RTUs would be required to have a redundant path into the control center. Also, it is unclear if one of those paths were to be unavailable for a certain amount of time, would the RC, TOP, or BA be non-compliant, because the redundancy is no longer available? It seems the standard should somehow account for data communicated over RTUs and not necessarily require each be fully redundant especially since the loss of one doesn't necessarily mean any significant loss of system visibility. Does the standard require redundant and diversely routed data exchange infrastructure for all data communications or just data communication between RC, TOP, BA control centers?	
Likes 0	
Dislikes 0	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	
The standard requirements say that the RC, TOp and BA must have redundant and diversely routed data exchange infrastructure "within the control center." The standard seems to mean that as soon as the data path enters the walls of the control center building then it must be on fully redundant and diversely routed path. If data is received from individual RTUs from the TOp, each of those RTUs would be required to have a redundant path into the control center. Also, it is unclear if one of those paths were to be unavailable for a certain amount of time, would the RC, TOp, or BA be non-compliant, because the redundancy is no longer available? It seems the standard should somehow account for data communicated over RTUs and not necessarily require each be fully redundant especially since the loss of one doesn't necessarily mean any significant loss of system visibility.	

Does the standard require redundant and diversely routed data exchange infrastructure for all data communications or just data communication between RC, TOP, BA control centers?	
Likes 0	
Dislikes 0	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
The standard requirements say that the RC, TOp and BA must have redundant and diversely routed data exchange infrastructure "within the control center." The standard seems to mean that as soon as the data path enters the walls of the control center building then it must be on fully redundant and diversely routed path. If data is received from individual RTUs from the TOp, each of those RTUs would be required to have a redundant path into the control center. Also, it is unclear if one of those paths were to be unavailable for a certain amount of time, would the RC, TOp, or BA be non-compliant, because the redundancy is no longer available? It seems the standard should somehow account for data communicated over RTUs and not necessarily require each be fully redundant especially since the loss of one doesn't necessarily mean any significant loss of system visibility. Does the standard require redundant and diversely routed data exchange infrastructure for all data communications or just data communication between RC, TOP, BA control centers?	
Likes 0	
Dislikes 0	
Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	No
Document Name	

Comment	
defer to comments by Oliver Burke of Entergy. The standard requirements say that the RC, TOp and BA must have redundant and diversely routed data exchange infrastructure “within the control center.” The standard seems to mean that as soon as the data path enters the walls of the control center building then it must be on fully redundant and diversely routed path. If data is received from individual RTUs from the TOp, each of those RTUs would be required to have a redundant path into the control center. Also, it is unclear if one of those paths were to be unavailable for a certain amount of time, would the RC, TOp, or BA be non-compliant, because the redundancy is no longer available? It seems the standard should somehow account for data communicated over RTUs and not necessarily require each be fully redundant especially since the loss of one doesn’t necessarily mean any significant loss of system visibility. Does the standard require redundant and diversely routed data exchange infrastructure for all data communications or just data communication between RC, TOP, BA control centers?	
Likes 0	
Dislikes 0	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The standard requirements say that the RC, TOP and BA must have redundant and diversely routed data exchange infrastructure “within the control center.” The standard seems to mean that as soon as the data path enters the walls of the control center building then it must be on fully redundant and diversely routed paths. If data is received from individual RTUs from the TOP, each of those RTUs would be required to have a redundant path into the control center. It seems the standard should account for data communicated over RTUs and not require each be fully redundant especially since the loss of one doesn’t necessarily mean any significant loss of system visibility.	
Likes 0	

Dislikes 0	
Tyson Archie - Platte River Power Authority - 5	
Answer	No
Document Name	
Comment	

In the R20 language, “have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's Control Center”, the words “within the Transmission Operator’s Control Center” are ambiguous.

The NERC Glossary states: a Control Center is, “One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability task”.

The R20 language could be interpreted to imply that each individual Control Center must have redundant and diverse data exchange routes.

Or, The R20 language could be interpreted, along with the definition, to imply that one or more Control Center facilities together must have redundant and diverse data exchange routes.

The intent is for the Transmission Operator to continue exchanging Real-time data in the event that a data route is lost. The intent is not to ensure the Transmission Operator’s Control Center has a specific number of connections. To be complaint, an entity must demonstrate that the loss of a data route does not affect the exchange of Real-time data.

Platte River is suggesting that the Drafting Team update the language as follows:

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments.

Likes 0	
Dislikes 0	

Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
Please explain in the Rationale, the difference between the redundant infrastructure in R2 and that in R6. If it is the same infrastructure, then we suggest removing the reference to the redundant infrastructure in R6.	
Likes 0	
Dislikes 0	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP feels these requirements could be more apporpriately addressed in a separate COM Standard.	
Likes 0	
Dislikes 0	

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3	
Answer	No
Document Name	
Comment	

We have issue with the term “diversly routed” within the Control Center.

A “backup” communication/ICCP server in a Back Up Control Center, would not meet the requirements of this standard as written. It will require a second set of “infrastructure” in the Primary Control Center.

The potential for “scope adjustment”, is quite troublesome.

Does this mean cabling should be in separate cable trays or pass through separate floor penetrations to get to the exterior physical boundary of the Control Center?

If TAL puts in two of everything, but have them in the same rack, not good enough.

If we put them in separate racks on opposite sides of the room, getting there.

If we put them in separate racks on opposite sides of the room, powered by two different sources (one via UPS, the other house power) even better.

At what point do we have to have a separate room to house the alternate equipment? We do not require it for the core SCADA/EMS platforms.

While the standard leaves it up to the entity to determine what they want to do to accomplish compliance, it will ALWAYS be interpreted by an auditor that is it “diversely routed ‘within’ the Control Center.

The proposed requirements are changing the regulations to be a “best practice” which was not supposed to happen. We have plans and processes in place for when the RC or TOP/BA cannot monitor the equipment necessary to determine if an SOL is being exceeded, or if it is an IROL.

TAL recommends “Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure (less cabling) within the Transmission Operator's Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities identified for data needs in order for it to perform its Real-time monitoring and Real-time Assessments."

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Justin Wilderness - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	
What is the definition of Redundant and Diversely routed data exchange ?	
Likes 0	
Dislikes 0	
Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

As written, the current requrements for R20 are ambiguous as to what redundancy and diverse routing actually means. Does the redundancy and diverse routing apply equally at the Primary Contol Center and the Backup Control Center. If a utility uses its Backup Control Center as the location of its redundant and diversely routed data exchange capabilities and it is capable of tranfering system operations from its Primary Contol Center to its Backup Control Center within 2 hours as required in EOP-008, why would that not meet the FERC's directive to have "redundancy and diverse routing as stated in paragraph 47?" Instead, R20 states that such redundancy and diversity must be accomplished by infrastructure within the TOP's control center. This seems to limit the means to achieve redundancy and diversity to the specific location of the control center irrespective of other locations (i.e. backup control center) where redundancy and diversity may be acheived and done so in a more reliable manner since it exists at a facility that is geographically separate. Redundancy and diversity at one facility is not useful if that facility is not useable. That is why EOP-008 requires TOPs to have a Primary Contol Center and a Backup Control Center. The SDT for this project should not fail to take advantage of referencing redundancy and diverse routing that may have already been achieved by the implementaion of of a Backup Control Center as requried in EOP-008.	
Likes 0	
Dislikes 0	
Douglas Webb - On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1;	
Answer	No
Document Name	
Comment	
While we generally understand what the requirement is moving to address, there is additional clarification needed in order to understand what is representative of performance. The reference to "within the Control Center" is specific to ensure there is no single point of failure in the data transfer supporting the BES and to ensure its availability in continuous (availability in the context of the CIA Security Triad). In addition, there is subjectivity in the exact data exchanges intended for the associated obligations.	

With respect to communications and data exchanges between the RC, TOP and BA, there are relationships to many different Standards currently in force, as well as those in development. It would greatly benefit industry and the regulatory process to consider everything in flight and delineate the desired end-state for the total reliability objective in an effort to allocate the elements of the desired outcome to the appropriate places either in existing standards or development. KCP&L agrees that the definition of critical data and validation that the appropriate data is available should be required, though, with additional clarification to what the SDT has proposed. We recommend adding these clarifications to the proposed drafted requirements and specific expectation that availability is the goal (if that is the case).	
Likes 0	
Dislikes 0	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	2016-01_TOP-001-4_Draft-1_Question-2.docx
Comment	
The “within the Control Center” wording is limiting and problematic for entities with redundant and diversely routed data exchange infrastructure across Control Centers; e.g. infrastructure that spans an entity’s primary and back-up Control Center locations. The current wording limits redundant infrastructure to “infrastructure ***within*** the … Control Center” which may be read	

as a ***single*** location, requiring entities with redundant and diversely routed data exchange infrastructure across control centers to install additional redundancy within a single Control Center location. Arizona Public Service (APS) recommends the language for R20 and R23 be modified as follows to recognize redundant data exchange capability infrastructure across an entity's ***collective*** Control Center facilities:

R20. Each Transmission Operator shall have data exchange capabilities, which are implemented through ~~with~~ redundant and diversely routed data exchange infrastructure maintained by ~~within~~ the Transmission Operator~~'s~~ at its Control Center(s), for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments.

R23. Each Balancing Authority shall have data exchange capabilities, which are implemented through ~~with~~ redundant and diversely routed data exchange infrastructure maintained by ~~within~~ the Balancing Authority~~'s~~ at its Control Center(s), for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments.

In addition, APS is requesting additional clarification be made to the **Rationale for Requirements R19/R20 and R22/R23**, as follows (if this is the SDT's intent):

"Redundant and diversely routed data exchange capabilities consist of infrastructure that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's (TOP) Control Center. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP Control Center. Moreover, diverse routing may be achieved by diversity of path and does not require an entity to use two different forms of communication media.

Likes 0	
Dislikes 0	
David Kiguel - 8	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Oshani Pathirane - On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3;

Answer	Yes
Document Name	
Comment	

Hydro One Networks Inc. will only be commenting on TOP-001-4 R20 for this question (IRO-002-5 R2 and TOP-001-4 R23 are not applicable to Hydro One Networks Inc.). Hydro One Networks Inc. is satisfied with TOP-001-4 R20.

Likes 0	
Dislikes 0	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	
Comment	

It would be helpful to add clarity in the Rationale that ‘redundant and diversly routed’ does not also require ‘dual data connection links’ (aka dual fiber) to each entity. Any revisions to the rationale should also be reflected in the ‘Note to Auditor’ section(s) of the RSAWs.

Does the requirement for redundant infrastructure also apply to data exchange capabilities housed at the backup Control Center?

We also suggest some additional rationale to clarify that loss of redundancy (loss of a single component within the Control Center infrastructure) due to a contingency and thus operating after that contingency for a period of time while the redundancy is recovered does not constitute a violation of TOP-001-4 R20. The example is loss of a network switch that must be replaced. Until it can be ordered

and installed, the redundancy may not be present. How would that situation fit into the context of R20? Any revisions to the rationale should also be reflected in the 'Note to Auditor' section(s) of the RSAWs.	
Likes 0	
Dislikes 0	
Stephanie Burns - On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1;	
Answer	Yes
Document Name	
Comment	
ITC concurs with the comments and position provided by SPP.	
Likes 0	
Dislikes 0	
Stephanie Burns - On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1;	
Answer	Yes
Document Name	
Comment	
ITC concurs with the comments and position provided by SPP.	
Likes 0	
Dislikes 0	
sean erickson - Western Area Power Administration - 1	

Answer	Yes
Document Name	
Comment	
In FERC Order 817 (Para. 47), NERC was directed to address "redundancy and diverse routing of data exchange capabilities" in the IRO/TOP standards. However, the SDT has duplicated this language in R20 and R23 identically. The challenge to TOPs and BAAs is to know what "diverse routing" means and how to implement it. Based upon comments from the SDT subsequent to releasing the proposed TOP-001-4 changes, it is clear that the SDT meant to assure that single point-of-failures do not compromise data exchange. **Therefore, it is recommended to replace (in R20) "redundant and diversely routed data exchange infrastructure within the Transmission Operator's Control Center" with the following: "redundant data exchange infrastructure not susceptible to a single point-of-failure within the Transmission Operator's Control Center".**	
Likes 0	
Dislikes 0	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Replace the word diverse routing with another word like "separated" or phrase like "redundancy designed to avoid a single point of failure".	
Likes 0	
Dislikes 0	
Quintin Lee - Eversource Energy - 1	
Answer	Yes

Document Name	
Comment	
Replace the phrase 'diversely routed' with another word like ‘separated’ or phrase like ‘redundancy designed to avoid a single point of failure’.	
Likes 0	
Dislikes 0	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	
Comment	
It would be nice if redundant and diversely routed where defined terms.	
Likes 0	
Dislikes 0	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Agree for TOP-001-4. No comments on the IRO-002-5 standard as it does not apply to ATC directly.	
Likes 0	

Dislikes 0	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
In addition to the TOP-001-4 requirements included in Q2 above, Dominion believes that Requirements 19 and 22 also address the FERC directive for redunancyand diverse routing capabilities.	
Likes 0	
Dislikes 0	
Chris Scanlon – Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Stanley Beasley - On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Stanley Beasley - On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Joshua Smith - On Behalf of: Lee Maurer, Oncor Electric Delivery, 1;	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Thomas Foltz – AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
We understand that these changes are to address a FERC Directive.	
Likes 0	
Dislikes 0	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	

Comment	
ERCOT joins the comments submitted by the IRC Standards Review Committee (SRC). We understand that these changes are in direct response to a FERC Directive and neither agree nor disagree.	
Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	
Document Name	
Comment	
No opinion	
Likes 0	
Dislikes 0	
Emily Rousseau – MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
We understand that these changes are to address a FERC Directive.	
Likes 0	
Dislikes 0	

3. The SDT has developed IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24 to address directives for testing redundancy of data exchange capabilities used in RC, TOP, and BA control centers. Do you agree with the proposed requirements? If you do not agree, or if you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.

Summary Consideration. The SDT thanks all commenters. In response to stakeholder comments, the SDT has modified the periodicity required for testing the redundant functionality of data exchange capabilities to quarterly (within 90 calendar days from the previous test). The SDT agrees with stakeholders that testing on a quarterly basis, rather than monthly, will better support reliability by allowing applicable entities to balance operating and testing requirements. The SDT has also clarified that the testing is required for primary Control Centers consistent with the directive in Order No. 817. Finally, the SDT modified the measures for these requirements to include use of evidence from an actual event that demonstrated the redundant functionality in satisfying the testing requirement.

Other specific comments and SDT responses are provided below:

- **A commenter recommended revising the proposed requirements to require complete testing of all failure modes. Another commenter recommended prescribing a rigorous data exchange testing and monitoring program.** The SDT does not believe that a more prescriptive requirement benefits reliability. The proposed requirements, along with Rationale and RSAW material, support the development of entity-tailored testing procedures.

- **A commenter recommended revising the requirements to allow for infrastructure monitoring in place of testing.** The SDT agrees that monitoring can identify failures in data exchange capabilities, however testing for redundant functionality provides additional reliability benefit of identifying issues that may not always be detected in monitoring. Accordingly, the SDT does not support the proposed change.

Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

As stated above, if redundancy and diverse routing are achieved by the use of a Primary Contol Center and a Backup Control Center as provided for in EOP-008, testing of this capability needs to reference the testing required for the Backup Control Center. While the EOP-008 testing requirement is for an annual test, R21 is proposing one test per calendar month. The FERC in paragraph 51 has provided no directive on how often to conduct these tests. The FERC directive only requires that the standard revison “addresses a data exchange capability testing framework for the data exchange capabilities used in the primary control centers to test the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority.” There is nothing in the directive that would prevent the annual testing of the Backup Control Center’s redundancy and diverse routing capabilities from meeting the requirements of the FERC directive. The SDT should change the testing from calendar month to annual and should also add a reference that states “If a Backup Control Center is used to provide the necessary redundancy and diverse routing as required in R20, TOPs will include tests to verify the alternate or less frequently used data exchange capabilities in the annual testing of the Backup Control Center as requred by EOP-008.”	
Likes 0	
Dislikes 0	
Thomas Foltz – AEP - 5	
Answer	No
Document Name	
Comment	
AEP believes that region-wide testing of data exchange capabilities for redundant functionality at least once each calendar month would be excessive. There is already an element of risk associated with this volume of testing, and testing on a monthly basis would potentially exacerbate that risk with no benefit to reliabilty. Rather than testing once a month, we believe testing once a calendar quarter is more appropriate. As a result, AEP recommends R21 be re-written as “Each Transmission Operator shall schedule a test of its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar quarter, subject to system conditions, with a test to be completed no less than once per calendar quarter. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality.”	
Likes 0	

Dislikes 0	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	No
Document Name	
Comment	
Testing of backup capability is already included in EOP-008 and is only tested on an annual basis. While this requirement adds specificity for data exchange capability, a monthly testing requirement is excessive and could be quite burdensome for some entitites.	
Likes 0	
Dislikes 0	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3	
Answer	No
Document Name	
Comment	
Since every test involves a forced interruption of the data, TAL recommends the testing be required QUARTERLY.	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	

Comment	
The requirement for testing the redundant communications paths on a monthly basis is unnecessarily onerous. Some pieces of the data path could easily be tested though normal failovers when patching while others may require isolating routers and letting data failover to the redundant communication paths. This could potentially degrade real-time operations reliability if the failover is unsuccessful. While testing backup circuits is important, too much testing could decrease system reliability. Quarterly or bi-annual testing of the redundant circuits would be more appropriate. The FERC order only mentions testing facilities in primary control center. Does the standard intend to require testing the redundancy of data exchange capabilities at primary and back-up control centers?	
Likes 0	
Dislikes 0	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
The requirement for testing the redundant communications paths on a monthly basis is unnecessarily onerous. Some pieces of the data path could easily be tested though normal failovers when patching while others may require isolating routers and letting data failover to the redundant communication paths. This could potentially degrade real-time operations reliability if the failover is unsuccessful. While testing backup circuits is important, too much testing could decrease system reliability. Quarterly or bi-annual testing of the redundant circuits would be more appropriate. The FERC order only mentions testing facilities in primary control center. Does the standard intend to require testing the redundancy of data exchange capabilities at primary and back-up control centers?	
Likes 0	
Dislikes 0	

Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	No
Document Name	
Comment	

Defer to comments from Oliver Burke of Entergy:

The requirement for testing the redundant communications paths on a monthly basis is unnecessarily onerous. Some pieces of the data path could easily be tested though normal failovers when patching while others may require isolating routers and letting data failover to the redundant communication paths. This could potentially degrade real-time operations reliability if the failover is unsuccessful. While testing backup circuits is important, too much testing could decrease system reliability. Quarterly or bi-annual testing of the redundant circuits would be more appropriate.

The FERC order only mentions testing facilities in primary control center. Does the standard intend to require testing the redundancy of data exchange capabilities at primary and back-up control centers?

Likes 0	
Dislikes 0	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

The requirement for testing the redundant communications paths on a monthly basis is unnecessarily onerous. Some pieces of the data path could easily be tested though normal failovers when patching while others may require isolating routers and letting data failover to the redundant communication paths. This could potentially degrade real-time operations reliability if the failover is unsuccessful. While

testing backup circuits is important, too much testing could decrease system reliability. Bi-annual testing of the redundant circuits would be more appropriate. The FERC order only mentions testing facilities in the primary control center. Does the standard intend to require testing the redundancy of data exchange capabilities at primary and back-up control centers?	
Likes 0	
Dislikes 0	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The FERC directive addresses testing the unused route for data exchange. The requirement as written would require testing both the primary and alternate data exchange infrastructure even if it is used every day. SRP recommends reqriting the requirement to more closely reflect the directive to test only the communication infrastructure that is not used during the month. SRP also recommends providing the opportunity for an entity to use a successful operation of the communication capabilities to alternatively verify the capabilities.	
Likes 0	
Dislikes 0	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC	
Answer	No
Document Name	
Comment	

R21 should be revised to be a quarterly test rather than a monthly test. We propose a complete test (EMS failover from the primary to backup) to be conducted quarterly instead of an incomplete test of different components once a month. A thorough test conducted quarterly is more effective to ensure reliability. Also in the 'Rationale for Requirement R21' box add a statement like 'for example either planned or unplanned failovers' immediately after: 'When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.'	
Likes 0	
Dislikes 0	
Kelly Silver - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	No
Document Name	
Comment	
R21of TOP-001 and R3 of IRO-002 should be revised to be a quarterly test rather than a monthly test. We propose a complete test (EMS failover from the primary to backup) to be conducted quarterly instead of an incomplete test of different components once a month. A thorough test is more effective to ensure reliability	
Likes 0	
Dislikes 0	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	

Recommend that testing be done quarterly. Also in the 'Rationale for Requirement R21' box add a statement like 'for example either planned or unplanned failovers' immediately after: 'When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.'	
Likes 0	
Dislikes 0	
Oshani Pathirane - On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3;	
Answer	No
Document Name	
Comment	

Hydro One Networks Inc. will only be commenting on TOP-001-4 R21 for this question (IRO-002-5 R3 and TOP-001-4 R24 are not applicable to Hydro One Networks Inc.). Hydro One Networks Inc. has cast a negative ballot on the standard due to the following two concerns with R21. A favourable ballot, however, has been cast on the poll associated with the VRFs/VSLs and Implementation Plan.

I. Hydro One Networks Inc. would like to support the NPCC RSC's comment on suggesting that the drafting team consider R21 be modified to require quarterly (and not monthly) testing of redundant capability. This is because in order to conduct a thorough redundancy test, the primary system would need to be failed intentionally by shutting it down, thereby increasing the risk to reliability during the completion of the failover. Therefore, such a risk to reliability, even for the purpose of conducting a test, should be minimized by performing the test quarterly at most (or ideally, twice annually) and not once per calendar month as is presently specified in R21.

II. **Hydro One Networks Inc. would also like to thank the drafting team for providing us with clarity (during the Industry Webinar held on July 22, 2016) that actual events could typically constitute testing of redundancy for those hot standby systems where failover from the primary path to a secondary one is exercised in real-time and where both data exchange paths are continuously monitored for any failure. However, Hydro One Networks Inc. strongly recommends that the drafting team adds this to M21 in order to provide clarity to those entities who own such hot standby systems.**

Likes 0	
Dislikes 0	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern believes that the SDT should not include a requirement for monthly testing. The standard (as currently written), fails to address data exchange architectures that reside outside of the RC control center. In addition, the standard (as currently written), has a great deal of overlap with EOP-008, which already addresses redundancy, diversity, along with testing at a system level for a broad range of functionalities. The requirement for testing the redundant communications paths on a monthly basis is unnecessarily onerous. Some pieces of the data path could easily be tested though normal failovers when patching while others may require isolating routers and letting data failover to the redundant communication paths. This could potentially degrade real-time operations reliability if the failover is unsuccessful. While testing backup circuits is important, too much testing could decrease system reliability. Quarterly or bi-annual testing of the redundant circuits would be more appropriate. The FERC order only mentions testing facilities in primary control center. Does the standard intend to require testing the redundancy of data exchange capabilities at primary and back-up control centers?	
Likes 0	
Dislikes 0	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy believes that testing of data exchange capabilities every month would be overly burdensome. For an entity to have to power down, and physically test redundant switches and firewalls to ensure they do in fact switch, would be challenging to accomplish monthly. We request the drafting team to consider extending the timeframe for testing to once a year. Requiring testing once a year reduces burden on entities while maintaining the spirit of the FERC directive. Duke Energy also recommends that in an instance where an event occurs, and failovers work as intended, this should count as evidence that the entity tested the redundant functionality of its data exchange capabilities for that year.	
Likes 1	New York State Reliability Council, 10, ADAMSON ALAN
Dislikes 0	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC Standards Review Committee (SRC). We understand that these changes are in direct response to a FERC Directive and neither agree nor disagree; however, given the impact on real-time monitoring/operations, we are concerned with the periodicity and suggest it be modified from monthtly to quarterly.	
Likes 0	
Dislikes 0	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Please see Texas RE's answer for #2 regarding the language "within the [RC's and TOP's] Control Center."	
Likes 0	
Dislikes 0	
David Bueche - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy does not agree with the monthly periodicity for testing redundancy of data exchange capability. If an operational failover is required for testing, performing that task once per month is not practical. CenterPoint Energy recommends the periodicity should be no less than semi-annually.

CenterPoint Energy requests R21 be more descriptive in its requirement for testing. There could be configurations, which provide redundancy for data exchange capabilities, which are continuously monitored, alarmed, etc. while sharing and communicating information between 'primary' and 'alternate' infrastructure. CenterPoint Energy suggests the following language:

R20. Each Transmission Operator shall verify redundancy of data exchange capability by perfoming one of the following semi-annually:

R20.1. Functional test of redundant functionality

R20.2. Successfully exercising redundant functionality due to an actual event

R20.3. Continuoulsy monitor redundant functionality for status, accuracy, and availability.

If the method used for verification is unsuccessful at any time, the Transmission Operator shall intiate action within two hours to restore redundant functionality.

Likes 0	

Dislikes 0	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
(1) We request clarification on the application and intent of testing the redundancy of data exchange capabilities. Does testing imply a requirement to also test the redundancy found within the backup Control Center? The backup Control Center functionality is tested at least annually, per EOP-008. The requirement in TOP and IRO to test data exchange should apply only to the primary Control Center. We suggest editing the requirement to be clear that the testing should only apply to the primary center's redundancy. (2) We have a concern that monthly testing could lead to an increase in the amount of 'outage requests' submitted by TOP's to RC's, and therefore is unduly burdensome. TOP's are required to coordinate with the RC and others when failing over their data exchange tools. We suggest increasing the testing time period to quarterly, or even annually to align with EOP-008.	
Likes 0	
Dislikes 0	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	

Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	

Need to indicate within the requirement the testing is required for only the primary control centers and not back up control centers. The FERC Order indicates testing is only needed for the primary control centers. Also, recommend that testing be conducted quarterly instead of monthly.

Again, guidelines and technical basis on what is required testing would be helpful for the industry. For example, can real-time failovers be constituted as a test?

Likes 0	
Dislikes 0	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	

The requirements for testing are vague and not sufficiently developed. This is wasteful of resources (time and capital) and will lead to unnecessary standard violations. The current zero defect regulation approach requires clear bright line criteria to define when an entity has met compliance. The vague rationale box language suggesting that entities examine "various failure modes" is fine in concept, but doesn't practically work in a zero defect mandatory standard and should be removed.

Likes 0	
Dislikes 0	

Chris Scanlon – Exelon - 1	
Answer	No
Document Name	
Comment	
Excelon Utilities agrees with the comments filed by PJM, specifically, we recommend the time be changed from monthly to quarterly. We believe this will be sufficient for reliability and a more efficient approach.	
Likes 0	
Dislikes 0	
Jeffrey Watkins - On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5;	
Answer	No
Document Name	
Comment	
NVE believes that testing the data exchange capabilities for redundant functionality at least once each calendar month is excessive. Since the test would require a forced interruption of the data, NVE feels that there is a an element of risk associated for the high volume of testing with no benefit to reliability. NVE feels that testing once a calendar quarter (or longer) would be more appropriate.	
Likes 0	
Dislikes 0	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	

Comment
While PNMR agrees there needs to be testing of the data exchange capabilities to address the directives, we do not agree the propose requirement is the correct way. Paragraph 51 of the FERC Order 817 states, "We believe that the structure of Reliability Standard COM-001-2, Requirement R9 could be a model for use in the TOP and IRO Standards." FERC states the R9 in COM-001-2 COULD be a model, but not that it "must be" or even "should be". The COM-001-2 model is testing voice capabilities that typically have no ability to be actively monitored or generate alerts upon failure, and thus more frequent manual testing is required. In addition to "tests…data exchange capabilities…for redundant functionality…" requires what exactly? Is it just taking down one component in the primary path from the data exchange device (i.e. ICCP server, mailbox RTU) to the Telco demark? Or is it taking down every possible component on the primary path to ensure automatic failover to the redundant path? If it is taking down every possible component then for one our Control Centers that is approximately 21 components per path. Testing that many monthly seems excessive. PNMR believes that a better model for testing already exists in the NERC standards in PRC-005-6. The data exchange capabilities are similar in nature to the Communication Systems used in relaying. Many can be monitored on a continuously basis or with periodic automatic testing, and with alarming for loss of function. However the data exchange capability should probably have only time-based maintenance methods to reduce the complexity of the requirement language and because there is little benefit to performance based over time based for the data exchange systems in scope. Also time-based maintenance methods are in line with COM-001-2 model proposed by FERC. Below is proposed requirement language where [X|Y] denotes choose X or Y and comments begin with "NOTE: and are encapsulated in parenthesis. <Start proposed language; kit bashed from existing PRC and CIP standards as well as the proposed TOP-001-4> [R21|R24]. Each [Transmission Operator | Balancing Authority] shall implement one or more documented processes comprising a *Data Exchange Maintenance Program (DEMP)* that collectively addresses each of the following requirements. [21|24].1. Identify the components that comprise the data exchange capabilities specified in Requirement [R20|R23] and designate the components that comprise the redundant functionality. [21|24].2. Identify the Entity that is responsible for the operations of each component. (NOTE: Some components of the system that comprises the data exchange capabilities may be owned by a TOP or BA and located at its Control Center, but managed and maintained by the Reliability Coordinator. The SDT needs to give consideration to some language, not included, as to who is responsible for coordination of testing and that other party must be available to support such testing.)

[21|24].3 Identify the Component Attributes in Table [DESIGNATION HERE] applicable to each component identified in [21|24].1. (NOTE: SDT would need to determine if RC controlled components need to be included as part of this identification. If they do then the standards need to have language where the RC must provide the information to the TOP or BA upon request.)

[21|24].4 Identify the maintenance intervals for each component identified in [21|24].1 where the interval shall not exceed the Maximum Maintenance Interval assigned to the corresponding Component Attribute in Table [DESIGNATION HERE]. (NOTE: SDT would need to determine if RC controlled components need this identification. If they do then the standard needs to have language governing who identifies the maintenance interval and how testing is coordinated.)

[21|24].5 Verify every five (5) years that loss of all components not identified as part of the redundant functionality results in data exchange capabilities being operational within five (5) minutes of the loss. (NOTE: The DEMP in x.1 through x.4 address individual component testing and maintenance. This requirement addresses testing the entire system of components to ensure all the components in the redundant infrastructure work in concert to maintain data exchange capabilities.)

[21|24].6 Include plans for restoring data exchange capabilities if failure of a component does not result in the failover to a redundant component or path and maintain data exchange capabilities. (NOTE: R20 and R23 do not require the data exchange capabilities to have failover capabilities to switchover to redundant components or diverse routes. Thus the Data Exchange Maintenance Program should include how failures are addressed as they arise if such failover capabilities do not exist.)

The proposed language includes a time horizon limit of five (5) minutes for any failover scheme to restore data exchange capability. While most network failover schemes operate within seconds, the failover schemes for ICCP servers may be between two (2) and five (5) minutes. The proposed text for Table [DESIGNATION HERE] which is mentioned in the proposed language is shown below in CSV format. This allows the SDT to copy and paste into a text file; open as a CSV in Excel; copy the table from Excel; and paste into Word to maintain table formatting with little effort.

Component Attributes,Maximum Maintenance Interval,Maintenance Activities

Any component not having any of the attributes below,4 Calendar Months,Verify the component is functional.

Any component part of an automatic failover scheme to preserve the data exchange capabilities within five (5) minutes of a failure,3 Calendar Years,Verify the automatic failover scheme preserves the data exchange capabilities within five (5) minutes of a failure.

"Any component with continuous monitoring or periodic automated testing for the functional state of the component, and alarming on loss of function.",3 Calendar Years,"Manually verify the component is in a functional state.

Verify the loss of function results in generation of an alarm."

"Any component with all of the following attributes:

*Part of an automatic failover scheme to preserve the data exchange capabilities within five (5) minutes of a failure

*Continuous monitoring or periodic automated testing for the functional state of the component, and alarming on loss of function",5 Calendar Years,"Verify the automatic failover scheme preserves the data exchange capabilities within five (5) minutes of a failure.

Manually verify the component is in a functional state.

Verify the loss of function results in generation of an alarm."

Likes 0	
Dislikes 0	

Douglas Webb - On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1;

Answer	No
Document Name	

Comment

The draft TOP-001-4 R21 and R24 are ambiguous as to the scope of the testing required under the Requirements. As drafted, it is unclear if the testing is inclusive of back-up Controls Centers and if the Requirements apply only within a Control Center or includes exchange of data between Control Centers.

R21: The TOP shall test its Control Center data exchange capabilities with its RC and BA. The Requirement considers only Control Centers which, by definition, “One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks...” (See NERC Glossary Terms). The Requirement language suggests only active Control Centers are to test data exchange capabilities and is silent on testing at back-up Control Center facilities.

Also, entities with back-up Control Centers will likely have primary and secondary data exchange servers and connections at their active Control Center and at their back-up Control Center. The Requirement's language does not address this set of facts.

While some TOPs do not have back-up Control Centers, adding language to the Requirement that either includes or excludes testing data exchange capabilities of back-up Control Centers will provide clear expectations and additional clarity for purposes of compliance.

In addition to, or as an alternative to including language in the Requirement that includes/excludes back-up Control Centers, a guidance and technical basis addendum to the Standard would provide clarity for purposes of implementation and compliance purposes.

R24: The language of this requirement creates similar issues outlined, above, regarding R21, and incorporated by reference.

Also, the language of R24 does not address, from a practical view, how a BA will test its data exchange capabilities without potentially impacting and interrupting every related RC and TOP's Control Center operations. Recognizing the capabilities and design of BA data systems are likely unique to each BA, such testing may actually put the reliability of the BES in peril should, as the Requirement contemplates, the test fail. It is not an unreasonable scenario that an unsuccessful fail over to the redundant system can cause a failed return to the primary system with the effect of disabling both systems. While other Standards address the failure of control systems, the potential, as the Requirement is written, may create unintentional consequences, like a disabling of a Control Room's view of real-time data.

Additionally, the Standard would be enhanced by adding technical considerations, as an addendum to the Standard, that address the technical implications of BAs testing data exchange capabilities and assessment of the potential risk of a complete disruption of the availability of real-time data or other unintended consequence.

As stated previously, consideration of related drafting actions in process or other outstanding FERC directives would be prudent as the efforts continue to respond to the existing expectations for redundant and diverse data exchanges.

Likes 0	
Dislikes 0	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Justin Wilderness - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
It appears that a hardware failure would put us in concompliance, since we would not be able to restore in under 8 hours.	
Likes 0	
Dislikes 0	
David Kiguel - 8	
Answer	Yes

Document Name	
Comment	
Testing redundancy of data exchange capabilities used in RC, TOP, and BA control centres is necessary. However, monthly tests seem to be excessive. Quarterly tests would be more appropriate and sufficient to ensure functionality.	
Likes 0	
Dislikes 0	
Joe Tarantino - On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 3, 4, 1, 5, 6; Beth Tincher, Sacramento Municipal Utility District, 3, 4, 1, 5, 6; Jamie Cutlip, Sacramento Municipal Utility District, 3, 4, 1, 5, 6; Kevin Smith, Balancing Authority of Northern California, 1; Kimberly Neely, Sacramento Municipal Utility District, 3, 4, 1, 5, 6; Susan Oto, Sacramento Municipal Utility District, 3, 4, 1, 5, 6;	
Answer	Yes
Document Name	
Comment	
While SMUD/BANC agrees with the proposed requirement we repecfully request clarification on the following: 1. Whether the data exchange capability test is for each link or verification of the link's infrastructure; and, 2. Whether verification of continuous real-time data exchange of the data links constitute testing.	
Likes 0	
Dislikes 0	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	

Comment	
Agree for TOP-001-4. No comments on the IRO-002-5 standard as it does not apply to ATC directly.	
Likes 0	
Dislikes 0	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	
Comment	
A functional entity is required to "initiate action" after an unsuccessful test of redundant communications functionality. However, there is no requirement for that functionality to eventually be restored - there is no check or requirement regarding repair actions that are initiated but fail to be completed. This does not appear to adequately address the reliability risk.	
Likes 0	
Dislikes 0	
Stephanie Burns - On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1;	
Answer	Yes
Document Name	
Comment	
ITC concurs with the comments and position provided by SPP.	
Likes 0	
Dislikes 0	

Stephanie Burns - On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1;	
Answer	Yes
Document Name	
Comment	
ITC concurs with the comments and position provided by SPP.	
Likes 0	
Dislikes 0	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Does testing of the redundancy imply a requirement to also test the redundancy found within the backup Control Center monthly? The backup Control center functionality is tested at least annually per EOP-008. The requirement in TOP and IRO to test data exchange should apply only to the primary Control Center. We suggest editing the requirement to be clear that the testing should only apply to the primary center's redundancy. We have a concern that monthly testing could lead to a vast increase in the amount of 'outage requests' submitted by TOP's to RC's. TOP's are required to coordinate (and in some cases gain approvals) with the RC and others when failing over their data exchange tools. We suggest perhaps increasing the time period to require perhaps quarterly testing or even test once every six months.	
Likes 0	
Dislikes 0	

ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Joshua Smith - On Behalf of: Lee Maurer, Oncor Electric Delivery, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Chris Gowder - On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; , Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Stanley Beasley - On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Stanley Beasley - On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Emily Rousseau – MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
We understand that these changes are to address a FERC Directive.	

Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	
Document Name	
Comment	
No opinion	
Likes 0	
Dislikes 0	
Matthew Beilfuss - WEC Energy Group, Inc. - 1,3,4,6 - MRO,RF	
Answer	
Document Name	
Comment	
The proposed TOP-001-4 requirements (R22, R23, and R24) would better fit in TOP-003-Operational Reliability Data.	
Likes 0	
Dislikes 0	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	

Comment	
We understand that these changes are to address a FERC Directive.	
Likes 0	
Dislikes 0	

4. Do you agree with the Implementation Plan for the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

Summary Consideration. The SDT thanks all commenters. The SDT is not proposing changes to the Implementation Plan. Some commenters recommended longer implementation periods due to uncertainty in the scope of requirements and concerns that significant infrastructure changes could be required. The SDT believes revisions to the requirements and rationale in the current draft provide clarity that the scope of the requirements are aimed at the applicable entity's primary Control Center. Furthermore, the SDT maintains that, based on comments received to date, any infrastructure changes needed to comply with the proposed requirements should be executable within the proposed implementation period.

Douglas Webb - On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1;

Answer	No
Document Name	

Comment

The Infrastructure changes and implications for the existing CIP standards may take time to enable. These changes may necessitate investments requiring entities to work with external suppliers, as well as entity approval processes through budget cycles and implementation time. We believe 24 months to be more appropriate for any infrastructure build out what may be necessary for entities to comply.

Likes 0	
Dislikes 0	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	No
Document Name	

Comment	
PNMR disagrees with the IRO and TOP having two separate implementation dates. If the purpose is to require the RC to establish redundancy first then the implementation should be phased on a requirement level. The data exchange capabilities for Reliability Coordinators (IRO-002-5 R2) could be "the first day…that is three months after the effective date…." The data exchange capabilities for TOP and BA (TOP-001-4 R20 and R23) could be "the first day…that is twelve months after the effective date…." However the testing requirements could be muddled based on our response to question #3. Thus the implementation for RC, BA, and TOP for testing requirements should be implemented at the same time especially if an RC to TOP or RC to BA coordination is required for testing as mentioned in our response to question #3.	
Likes 0	
Dislikes 0	
Jeffrey Watkins - On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5;	
Answer	No
Document Name	
Comment	
Depending on which non-BES facilities are identified in Requirement 10, additional infrastructure may be required to bring back the necessary information. In that scenario, more time may be needed than what is proposed. Until the scope of work is better clarified for the diverse and redundant routing, it is unclear whether or not the implementation plan is appropriate.	
Likes 0	
Dislikes 0	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment	
“Necessary” and “testing” are not defined enough to support the implementation plan.	
Likes 0	
Dislikes 0	
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Suggest that the implementation period for IRO-005-2 be the same 12 month period as TOP-001-4 based on the similiarity of the new requirements.	
Likes 0	
Dislikes 0	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We have concerns that some entities may need to procure additional equipment for redundant servers at their backup sites. This may not be feasible for smaller entities. We recommend lengthening the implementation period for TOPs to 24 months.	
Likes 0	
Dislikes 0	

Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Depending on the response to the level of required redundancy (and testing of said redundancy) within backup Control Center's, some entities may need to purchase equipment or redundant servers for their backup sites. This may require lengthening the implementation period beyond 12 months for TOP-001-4 and 3 months for IRO-002-5.	
Likes 0	
Dislikes 0	
Stephanie Burns - On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1;	
Answer	No
Document Name	
Comment	

ITC concurs with the comments and position provided by SPP.	
Likes 0	
Dislikes 0	
David Bueche - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy does not agree with the Implementation Plan associated with the current language in the revised Requirments. If Entities are going to be expected to provide redundant infrastructure for data exchange capabilities to exist within one Control Center, then CenterPoint Energy recommends an Implementation Plan of no less than 36 months. A configuration as decribed in the current proposal could require purchasing, installing, and training on new infrastructure that cannot be realistically completed in 12 months.	
Likes 0	
Dislikes 0	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC Standards Review Committee (SRC). The three-month implementation period for IRO-002-5 may not be adequate for all entities; suggest it be six-months.	
Likes 0	

Dislikes 0	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy disagrees with the suggested implementation for IRO-002-5. We feel that the Implementation Plans should mirror each other, and should be a 12 month implementation plan for both standards. The standards are basically asking each function to do the same thing, and all should have equal time to implement. Also, in some instances the RC may need to request data from TOP(s), which could take some time to turn around.	
Likes 0	
Dislikes 0	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Given the expansion of TOP-001-4 scope to include non-BES equipment in the data specification for Operational Planning Analyses, Real-time monitoring, and Real-time Assessments performed by the TOP in accordance with TOP-003-3, significant preparation, study, and coordination is necessary for all TOPs to comply with the new requirements. **Therefore, the implementation plan of 12-months is too short to reasonably complete all preparations and testing. A minimum of a 36-month implementation plan is recommended to best achieve the required changes to reliability functions.**	
Likes 0	
Dislikes 0	

Chris Gowder - On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; , Group Name FMPA	
Answer	No
Document Name	
Comment	
Three months is not enough time to ensure the appropriate infrastruction and documentation is in place to meet the expectations of the requirements. FMPA suggests a 12 month implementation period for IRO-002-5.	
Likes 0	
Dislikes 0	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The effective date for IRO-002-5 of three months is too short. Testing processes would need to be put into place with each TOp and BA in the RC area. Three months does not seem like sufficient time to develop and coordinate the testing processes in order to ensure that they can be done consistently and on time. Suggest the implementation period for IRO-002-5 be the same 12 month period as with TOP-001-4 based on the similarity of the new requirements.	
Likes 0	
Dislikes 0	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The effective date for IRO-002-4 of three months is too short. Testing processes would need to be put into place with each TOP and BA in the RC area. Three months is not sufficient time to develop and coordinate the testing processes in order to ensure that they can be done consistently and on time. The implementation period for IRO-002-5 should be the same 12 month period as with TOP-001-4 based on the similarity of the new requirements.	
Likes 0	
Dislikes 0	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
APS is concerned that the acceptability of the implementation plan depends upon the final wording of TOP-001-4, requirements R20 and R23, and what is required to demonstrate redundancy and diverse routing as described in our comments to question #2 above. Until those concerns are resolved, it cannot support the implementation plan as proposed.	
Likes 0	
Dislikes 0	
Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	No

Document Name	
Comment	
Defer to comments by Oliver Burke of Entergy: The effective date for IRO-002-5 of three months is too short. Testing processes would need to be put into place with each TOp and BA in the RC area. Three months does not seem like sufficient time to develop and coordinate the testing processes in order to ensure that they can be done consistently and on time. Suggest the implementation period for IRO-002-5 be the same 12 month period as with TOP-001-4 based on the similarity of the new requirements.	
Likes 0	
Dislikes 0	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
The effective date for IRO-002-5 of three months is too short. Testing processes would need to be put into place with each TOp and BA in the RC area. Three months does not seem like sufficient time to develop and coordinate the testing processes in order to ensure that they can be done consistently and on time. Suggest the implementation period for IRO-002-5 be the same 12 month period as with TOP-001-4 based on the similarity of the new requirements.	
Likes 0	
Dislikes 0	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No

Document Name	
Comment	
The effective date for IRO-002-5 of three months is too short. Testing processes would need to be put into place with each TOp and BA in the RC area. Three months does not seem like sufficient time to develop and coordinate the testing processes in order to ensure that they can be done consistently and on time. Suggest the implementation period for IRO-002-5 be the same 12 month period as with TOP-001-4 based on the similarity of the new requirements	
Likes 0	
Dislikes 0	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3	
Answer	No
Document Name	
Comment	
TAL believes three months is insufficient to perform the physical modifications that may be needed to obtain the "diverse routing" as proposed. At least 12-months will be required since the modifications to storm hardened buildings may be required.	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Emily Rousseau – MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	

The three-month implementation period for IRO-002-5 may not be adequate for all entities; suggest it be six-months.	
Likes 0	
Dislikes 0	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Our response is in relation to our registration as a TOP and not for the RC.	
Likes 0	
Dislikes 0	
Oshani Pathirane - On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3;	
Answer	Yes

Document Name	
Comment	
Hydro One Networks Inc. is generally satisfied with the May 2016 draft of the NERC Implementation Plan for TOP-001-4.	
Likes 0	
Dislikes 0	
Matthew Beilfuss - WEC Energy Group, Inc. - 1,3,4,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
No concerns with the timelines proposed with implementation plan for TOP-001-4 assumed 4/1/2018 based on current schedule. . No comments on the IRO-002-5 implementation timeline as it does not apply to ATC directly.	
Likes 0	

Dislikes 0	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Stanley Beasley - On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Stanley Beasley - On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
David Kiguel - 8	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Joshua Smith - On Behalf of: Lee Maurer, Oncor Electric Delivery, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Thomas Foltz – AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	
Document Name	
Comment	
No opinion	
Likes 0	
Dislikes 0	

5. ***Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs provide your recommendation and explanation.***

Summary Consideration. The SDT thanks all commenters. The SDT is not proposing any changes to VRFs in the current draft. The SDT revised VSLs for consistency with changes to the proposed requirements where necessary.

Specific comments and SDT responses are provided below:

- **A commenter recommended changing the VRFs for proposed TOP-001-4 Requirements R20 and R23 from *High* to *Medium* based on the VRF criteria.** The SDT determined that a VRF of *High* is consistent with NERC and FERC criteria. The SDT believes that a failure of data exchange capabilities necessary for performing Real-time monitoring and Real-time Assessments or analysis functions places the BES at an unacceptable level of risk. The SDT is not recommending a change to this VRF from the assigned level in approved TOP-001-3.
- **A commenter recommended revising the VSLs for proposed TOP-001-4 Requirement R10 to account for *as necessary* subparts.** The SDT revised the VSL as recommended.

Justin Wilderness - NiSource - Northern Indiana Public Service Co. - 1

Answer	No
Document Name	

Comment

The VFRs for R10 seem to severe for the large number of points that will be required. R21, R24 a hardware failure will likely put us in violation.

Likes 0	

Dislikes 0	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
Based on NERC's Violation Risk Factors guidance document (dated May 16, 2014), APS recommends that the SDT consider revising the VRFs for requirements R20 and R23 to *Medium* as the best fit definition because "if violated, they could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system" in real-time. "However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition."	
Likes 0	
Dislikes 0	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The VRF and VSL table would need to be adjusted to reflect the requested changes	
Likes 0	
Dislikes 0	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	

Answer	No
Document Name	
Comment	
Duke Energy recommends that the drafting team re-word the Severe VSL for R20 and R23 to more closely align with the language of the requirements. We suggest the following: *"The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, or the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments."*	
Likes 0	
Dislikes 0	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We do not agree with the High Violation Risk Factors identified for the proposed requirements. Testing, by itself, should not directly cause or contribute to a Bulk Electric System instability, separation, or a cascading sequence of failures. Hence, a Medium risk should be assigned to align with redundant communications capabilities. We ask the SDT to also provide clarification for requirement R10, stating that some of the items will only need to be exchanged if the TOP determines them to be necessary. This is contradictory to the VSLs for R10 that do not recognize that some of the items may not be necessary for TOPs.	
Likes 0	
Dislikes 0	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	

Answer	No
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR agrees with the Violation Risk Factors for all the requirements and most of the Violation Severity Levels. However the SDT may find the VSLs for TOP-001-4 R21 and R23 may need further revision after consideration of our response to question #3.	
Likes 0	
Dislikes 0	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
None.	

Likes 0	
Dislikes 0	
Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Agree for TOP-001-4. No comments on the IRO-002-5 standard as it does not apply to ATC directly.	
Likes 0	
Dislikes 0	
Stephanie Burns - On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1;	
Answer	Yes
Document Name	

Comment	
ITC concurs with the comments and position provided by SPP.	
Likes 0	
Dislikes 0	
Stephanie Burns - On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1;	
Answer	Yes
Document Name	
Comment	
ITC concurs with the comments and position provided by SPP.	
Likes 0	
Dislikes 0	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

For TOP-001-4 Requirement R10, Texas RE interprets the VSLs to mean the following:

- If an entity fails to monitor all Facilities per part 10.1, there is a violation with a lower VSL.
- If an entity fails to monitor 1/10 Facilities per part 10.1, there is a violation with a lower VSL.

- And so forth for parts 10.2 – 10.6.
- Adding the word “all” in subparts of TOP-001-4 R10 would add clarity to the requirements:
- 10.1 Monitor *all* Facilities…

10.2 Monitor the status of *all* Remedial Action Schemes…

10.3 Monitor *all* non-BES facilities…

10.4 Obtain and utilize status, voltages, and flow date for *all* Facilities outside…

10.5 Obtain and utilize the status of *all* Remedial Action Schemes…

10.6 Obtain and utilize status, voltages, and flow data for *all* non-BES facilities…

Likes 0	
Dislikes 0	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

In Requirement 10 of TOP-001-4, some of the items will only need to be exchanged if the TOP determines them to be necessary. However the VSL for R10 does not recognize that some of the items may not be necessary and the TOP may not be obtaining them.

Likes 0	
Dislikes 0	

Matthew Beilfuss - WEC Energy Group, Inc. - 1,3,4,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Oshani Pathirane - On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3;	
Answer	Yes
Document Name	
Comment	
Hydro One Networks Inc. is generally satisfied with the VRFs and VSLs presented in Draft 1 (May 2016) of TOP-001-4. Accordingly, a favourable position has been indicated in the associated poll.	
Likes 0	
Dislikes 0	
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Douglas Webb - On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1;	
Answer	Yes
Document Name	
Comment	
The VRFs and VSLs mirror the proposed revisions to the Standard is currently offered,	
Likes 0	
Dislikes 0	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Jack Stamper - Clark Public Utilities - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Jim Nail - City of Independence, Power and Light Department - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Anthony Jablonski - ReliabilityFirst - 10	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Joshua Smith - On Behalf of: Lee Maurer, Oncor Electric Delivery, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
David Kiguel - 8	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Richard Vine - California ISO - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Chris Gowder - On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; , Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Stanley Beasley - On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Stanley Beasley - On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Jeffrey Watkins - On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Emily Rousseau – MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	

Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	
Document Name	
Comment	
No opinion	

Likes 0	
Dislikes 0	

6. *Provide any additional comments for the SDT to consider, if desired.*

Summary Consideration. The SDT thanks all commenters. Specific comments and SDT responses are provided below:

- **A commenter recommended the SDT consider work being undertaken in Project 2016-02 Modifications to CIP Standards.** The SDT will maintain awareness and does not see any conflicts between the projects.
- **A commenter recommended changing proposed TOP-001-4 Section F Associated Documents due to perceived inconsistency with the NERC Glossary definition for Operating Plan.** The SDT does not agree that the section is inconsistent with the NERC definition. No changes have been made to this section since TOP-001-3 was approved by stakeholders.
- **A commenter recommended removing proposed TOP-001-4 Requirement R7 and replacing it with a guideline.** The suggested change is not in scope for Project 2016-01.
- **A commenter asked for clarification of the types of data exchange capabilities that are expected for performing Operational Planning Analysis as specified in proposed TOP-001-4 Requirement R19.** The proposed requirement provides flexibility for entities to use any data exchange capability that is needed to support their OPA obligations. Internet-protocol exchange, Web-based, email, or third-party systems such as SDX are some examples of data exchange capabilities that can fulfill this requirement, depending on the nature of the data required for OPA.
- **Commenters recommended various wording changes.** The SDT reviewed all recommendations and made changes that the SDT determined were appropriate.

Douglas Webb - On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1;

Answer	
Document Name	
Comment	

As a general comment, the SDT's work may materially be impacted by the scope and work on the Project 2016-02, Modifications to CIP Standards. There are areas that may conflict, such as the definition of Control Center and communication between Control Centers. It raises questions like, "Is the Standard only applicable to communication links between internal Control Centers or apply only to links with external Control Centers, such as between a TOP and BA's Control Centers?"

Recognizing the SDT can only address what is "true" today in advancing the project, consideration of the work and direction of the Project 2016-02 may provide insight and an opportunity to address and incorporate into the TOP and IRO Standards language that would better align with the potential modifications to the CIP Standards.

Likes 0	
Dislikes 0	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	
Document Name	

Comment

The recent webinar for this project demonstrated the current draft is still ambiguous and needs more language to clarify intent within the actual requirement and not just the rationale box. While we have tried to comment and provide language for the SDT to use, please consider making it clear in the standard what is required since that is what is enforceable and leaving any meat in the rationale box. For example R21 requires monthly testing, but the rationale indicate "…testing practices should, over time, examine the various failure modes of its data exchange capabilities." The rationale and requirement do not fully agree. The rationale gives an ambiguous time horizon for testing various failures modes while the requirement seems to indicate all failure modes are tested monthly. Please make sure any requirement language fully and clearly reflects the rationale.

Likes 0	
Dislikes 0	

Chris Scanlon – Exelon - 1

Answer	
Document Name	
Comment	
See above, quarterly vs monthly schedule . Thank you.	
Likes 0	
Dislikes 0	
Michael Shaw - Lower Colorado River Authority - 6, Group Name LCRA Compliance	
Answer	
Document Name	
Comment	
Both section 10.4, 10.5 and 10.6 describe a Transmission Operator Area which is a defined term in the NERC standard. This term is also utilized in many regional joint registration organizations. If this term is going to be utilized in the NERC standard to provide direct responsibility of the RAS. LCRA TSC believes that the responsibility descriptions should be better defined in the standard. One example of this is defining that if the operator/owner has an RAS they are responsible for monitoring it. If the RAS is owned and operated by another entity but is in a Transmission operators area the BA or owner/operator should be responsible for monitoring it. Not the TOP.	
Likes 0	
Dislikes 0	
Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper	
Answer	
Document Name	
Comment	

The use of "Facilities" capitalized in Requirement 10.1 means it is part of the BES. It may be helpful to reword as "Monitor BES Facilities" so it's obvious without having to review the definition of Facilities that this requirement is for BES facilities.	
Likes 0	
Dislikes 0	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
We ask that you reevaluate the TOP standard with the Enhanced Periodic Review Team if it is not already scheduled. It would be good to stabilize these two standards. The TOP standard is approaching 40 requirements and sub-bullets.	
Likes 0	
Dislikes 0	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
(1) We have concerns regarding the financial implications smaller entities will face with the increased level of redundancy and testing proposed for backup Control Centers. In order to meet these proposed requirements, some entities would need to make sizeable investments to procure redundant equipment and staff for their backup sites. We feel the cost factor would constitute an unduly and unreasonable burden placed on smaller entities.	

(2) We thank the SDT for this opportunity to comments on these standards.	
Likes 0	
Dislikes 0	
Matthew Beilfuss - WEC Energy Group, Inc. - 1,3,4,6 - MRO,RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	

Whenever a Standard references “Control Center”, Texas RE considers the reference to include any Control Center (primary, back-up, tertiary, etc.) as capabilities must be present (and redundant and diversely routed) for an entity to do Real-time monitoring and Real-time Assessments.

In the Evidence Retention section of TOP-001-4, it states: “For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for a full-time period since the last audit.” Rather than ask the entities to keep evidence outside of the specified evidence retention period, Texas RE recommends aligning all evidence retention to “since the last audit of the requirement”.

Texas RE noticed in Section F of TOP-001-4, “Associated Documents”, it appears that ‘Operating Plan” has an explanation that is inconsistent with the NERC Glossary of Terms. Texas RE recommends making them consistent.

TOP-001-4 R23 states: “Each Balancing Authority shall have data exchange capabilities…with its Reliability Coordinator”. There could be times when the Balancing Authority might need to coordinate and exchange data with a Reliability Coordinator that is not its own. Texas RE suggests changing “its” to “the applicable Reliability Coordinator”.

As written IRO-005-2 R3 refers to the test being unsuccessful and implies the test itself could not take place. Texas RE recommends revising the requirement is to say: "if the results of the test reveal there is no functionality…"

TOP-001-4 R7 is an extremely vague requirement. Texas RE suggests it might be better suited as a guideline.

Likes 0	
Dislikes 0	
Gregory DAnnibale - PSEG - PSEG Energy Resources and Trade LLC - NA - Not Applicable - NPCC	
Answer	
Document Name	
Comment	

No opinion	
Likes 0	
Dislikes 0	
Chris Gowder - On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; , Group Name FMPA	
Answer	
Document Name	
Comment	
The revised language of R19 in TOP-001 results in what some might consider a new requirement. While it is clear what type of data exchange capabilities are expected for exchanging real-time information, it is less clear what is expected for day-ahead information. Does email satisfy the requirement? Can third party systems, such as SDX, be used? FMPA believes additional clarity is needed.	
Likes 0	
Dislikes 0	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	
Document Name	
Comment	
Tri-State believes the Standard Drafting Team should clarify that TOP-001-4 R20 and R21 are applicable to only a TOP's primary Control Center. As the draft is currently written, it is unclear if the backup Control Centers are inadvertently included because NERC EOP-008-1	

requires an entity to meet its functional obligations in the event of the loss of the primary Control Center. The testing requirement for EOP-008-1 is on an annual basis which is not the same periodicity of the monthly test required in R21. Requiring monthly testing of the backup Control Center in accordance with the proposed TOP-001-4 R21 would add undue burden. Tri-State would like the Standard Drafting Team to explicitly exclude the backup Control Centers from these requirements.	
Likes 0	
Dislikes 0	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	

Jaclyn Massey - Entergy - Entergy Services, Inc. - 5	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Joshua Smith - On Behalf of: Lee Maurer, Oncor Electric Delivery, 1;	
Answer	
Document Name	
Comment	

Proposed TOP-001-4 R10 requires TOP's to ***monitor*** *its facilities, Remedial Action Schemes and Non-BES facilities that it identifies as necessary to determine SOL exceedances in R10.1, R10.2 and R10.3. For Sub-Requirements R10.4, R10.5 and R10.6 the wording has changed to "obtain and utilize" instead of the former "monitor" used in previous drafts of TOP-001-3. These Sub-Requirements also use the wording "identified as necessary by the Transmission Operator". The proposed TOP-001-4 RSAW requires the Transmission Operator to provide evidence that it monitored all the data stated in the Sub-Requirements without requiring the TOP to providing reasoning or qualifications for how the TOP determined what or how the data "obtained and utilized" was "identified as necessary". This creates unenforceable requirements that have no reason to be added to a Standard.*

Proposed TOP-001-4 R10.5 requires TOPs to obtain and utilize statuses of Remedial Action Schemes in neighboring TOP areas. Currently TOP SPS statuses is communicated through notifications required to the RC and affected TOPs. This notification process requirement works and keeps the wide area system monitoring and control responsibility on ERCOT the Reliability Coordinator and not on individual TOPs.

In closing, the ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to obtain and utilize data specified in R10.4, R10.5 and R10.6. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001- 4 does it require TOs to supply neighboring TOs with this data. Oncor requests R1O.4, R10.5, R10.6 be removed from the standard due to lack of regional flexibility.

Likes 0	
Dislikes 0	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	
Document Name	

Comment

City Light subject matter experts believe that the periodicity stated in R21 and R24 testing requirement of "*at least once each calendar month*" is excessive. The FERC directive states "*TOP and IRO standards that addresses a data exchange capability testing framework*". Based on our SMEs system experience, they believe that **quarterly** testing would be sufficient. Thank you for your consideration.

Likes 0	
Dislikes 0	

Emily Rousseau – MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	
Document Name	

Comment

It would be good to stabilize these two standards. The TOP standard is approaching 40 requirements and sub-bullets. Future changes should be based on data that shows a need for new requirements.

Likes 0	
Dislikes 0	

Jim Nail - City of Independence, Power and Light Department - 5

Answer	
Document Name	

Comment

We appear to be on a slippery slope of expanding the reach of the NERC Standards and mandatory compliance. If 100 kV is the appropriate threshold, then stick with it. If the threshold should be lower then build the case and make it official, not a piece at a time infiltrating our Distribution systems.

Likes 1	Smith Joshua On Behalf of: Lee Maurer, Oncor Electric Delivery, 1;
Dislikes 0	

Thomas Foltz – AEP - 5	
Answer	
Document Name	
Comment	
AEP has chosen to vote negative on TOP-001-4, driven by the concerns expressed above.	
Likes 0	
Dislikes 0	

End of Report