Exhibit A

Proposed Reliability Standards

Reliability Standard IRO-002-5 Clean and Redline

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-5
3. **Purpose:** To provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinators

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

R3. Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R3. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

R5. Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R4 and Measures M1, M2, and M4.
- The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 and Measures M5 and M6 for the current calendar year and one previous calendar year.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2.	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, as specified in the requirement.	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.
R3.	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	capabilities specified in Requirement R2 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Reliability Coordinator did not test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				maintenance of its telecommunication, monitoring and analysis capabilities.
R5.	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6.	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	FERC approval
5	February 9, 2017	Adopted by Board of Trustees	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 [project page].

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:
The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:
Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 (R6 in IRO-002-5) has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for Requirements R1 and R2:
The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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) primary 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. 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.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the RC's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R3:
The revised requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for R4 (R6 in IRO-002-5):
The requirement was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-~~4~~5
3. **Purpose:** ~~Provide~~To provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability ~~**Coordinator**~~Coordinators

5. **Effective Date:** See Implementation Plan~~.~~
6. ~~**Background:**~~

   ~~See the Project 2014-03 project page.~~

B. Requirements and Measures

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments.~~ . *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its ~~operational~~Operational Planning Analyses~~,~~.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring~~,~~ and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

R3. Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R3. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

~~R2.~~R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

~~M1.~~M4. Each Reliability Coordinator shall have, and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

~~R3.~~R5. Each Reliability Coordinator shall monitor Facilities, the status of ~~Special Protection Systems~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

~~M2.~~M5. ~~M3.~~ Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of ~~Special Protection Systems~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

~~R4.~~R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

~~M3.~~M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

~~As defined in the NERC Rules of Procedure,~~ "Compliance Enforcement Authority" ~~(CEA)~~ means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~**1.2. Compliance Monitoring and Assessment Processes:**~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~**1.4. Data Retention**~~

1.2. ~~The Reliability Coordinator~~**Evidence Retention:**

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and ~~R3~~R4 and Measures M1, M2, and ~~M3~~M4.
- The Reliability Coordinator shall ~~keep data or~~retain evidence for Requirement ~~R4~~R3 and Measure ~~M4~~M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 and Measures M5 and M6 for the current calendar year and one previous calendar year.

~~If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.~~

~~1.6.~~1.3. ~~The~~ **Compliance Monitoring and Enforcement** ~~Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~ **Program**

~~**1.7. Additional Compliance Information**~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

~~None~~.

~~Table of Compliance Elements~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~Operations Planning, Same-Day Operations, Real-time Operations~~	~~High~~	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2.	~~Operations Planning, Same-Day Operations, Real-time Operations~~	~~High~~	N/A	N/A ~~N/A~~	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, as specified in the requirement.~~The Reliability Coordinator~~	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					~~failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.~~	specified in the requirement.
R3.			~~Real-time Operations~~ The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center	~~High~~The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an	~~N/A~~The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange ~~N/A~~ ~~N/A~~	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Reliability Coordinator did not ~~monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its~~ test its primary Control Center data exchange capabilities

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	specified in Requirement R2 for redundant functionality; OR The Reliability Coordinator ~~Area and neighboring Reliability Coordinator Areas~~tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to ~~identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~within its Reliability Coordinator Area~~restore the redundant functionality.
R4.			N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
R5.			N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
~~R4~~**R6.**	~~Operations Planning, Same-Day Operations, Real-time Operations~~	~~High~~	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

~~E.~~ ~~Interpretations~~

~~None.~~

~~G.~~E. Associated Documents

~~None.~~

The Implementation Plan and other project documents can be found on the project page.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
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4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	FERC approval
5	February 9, 2017	Adopted by Board of Trustees	Revised

Guidelines and Technical Basis

None

Rationale~~:~~

During development of ~~this standard~~IRO-002-5, text boxes ~~were~~are embedded within the standard to explain the rationale for various parts of the standard. Upon ~~BOT approval~~Board adoption of IRO-002-5, the text from the rationale text boxes ~~was~~will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:

The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:

Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 (R6 in IRO-002-5) has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for Requirements R1 and R2:

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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) primary 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. 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.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the RC's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R3:

The revised requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for R4~~:~~ (R6 in IRO-002-5):

~~Requirement R4~~The requirement was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

Reliability Standard TOP-001-4 Clean and Redline

A. Introduction

1. **Title:** **Transmission Operations**
2. **Number:** TOP-001-4
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.2. Transmission Operator

   4.1.3. Generator Operator

   4.1.4. Distribution Provider

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and

provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings,

electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

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

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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 to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R22. Each Balancing Authority shall have data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M22. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 to perform its Real-time monitoring and analysis functions as specified in the requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.
- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R19, and Measure M15 through M19 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep data or evidence for Requirement R22 and Measure M22 for the current calendar year and one previous calendar year,

with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items	The Transmission Operator did not monitor, obtain, or utilize two of the items required or	The Transmission Operator did not monitor, obtain, or utilize three of the items required or	The Transmission Operator did not monitor, obtain, or utilize four or more of the items

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.
R11	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Center, as specified in the Requirement.	
R21	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				restore the redundant functionality.
R22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, as specified in the Requirement.	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.
R24	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test;

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is:
http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	February 9, 2017	Adopted by Board of Trustees	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

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 Transmission Operator 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 the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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 Transmission Operator's (TOP) primary 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. 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'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. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R21:

The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for Requirements R22 and R23:

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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 Balancing Authority's (BA) primary 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. Requirement R23 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 BA'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. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R24:

The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component(e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

A. Introduction

1. **Title:** **Transmission Operations**

2. **Number:** TOP-001-~~3~~4

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.2. Transmission Operator

   4.1.3. Generator Operator

   4.1.4. Distribution Provider

5. **Effective Date:** See Implementation Plan
   ~~See Implementation Plan.~~

~~6. **Background:**~~

~~See Project 2014-03 project page.~~

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following ~~as necessary~~ for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. ~~Within~~ Monitor Facilities within its Transmission Operator Area~~, monitor Facilities and~~;

~~**10.1.**~~ Monitor the status of ~~Special Protection Systems, and~~

10.2. ~~Outside~~Remedial Action Schemes within its Transmission Operator Area~~, obtain~~;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of ~~Special Protection Systems~~Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

~~10.2.~~10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

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

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of ~~Special Protection Systems~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of ~~Special Protection Systems~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

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

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. ~~M18.~~ Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

R19. Each Transmission Operator shall have data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in~~perform its ~~Transmission Operator Area.~~Operational Planning Analyses. [*Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations]~~]*

M19. ~~M19.~~ Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in~~perform its ~~Transmission Operator Area~~Operational Planning Analyses.

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

M20. ~~M20.~~ Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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 to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R22. Each Balancing Authority shall have data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M22. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

~~M20.~~M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, ~~operator logs,~~ system specifications, system diagrams, or other ~~evidence~~documentation that ~~it has~~lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability~~perform its Real-time monitoring and analysis functions as specified in ~~its Balancing Authority Area~~the requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
~~As defined in the NERC Rules of Procedure,~~ "Compliance Enforcement Authority" ~~(CEA)~~ means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~**1.2. Compliance Monitoring and Assessment Processes**~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~**1.2. ~~Data~~Evidence Retention:**
The following evidence retention ~~periods~~period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and ~~R15 through R20 and~~ Measure M1 through M11, ~~and M15 through M20~~ for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ~~ninety~~90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 ~~and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14~~.

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

- ~~If a Balancing Authority,~~Each Transmission Operator ~~, Generator Operator, or Distribution Provider is found non-compliant, it~~ shall ~~keep information related to the non-compliance until mitigation is complete~~retain evidence and ~~approved or the time period~~that it initiated its Operating Plan to mitigate a SOL exceedance as specified ~~above, whichever is longer~~in Requirement R14 and Measurement M14 for three calendar years.

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

~~1.4. Additional Compliance Information~~

- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R19, and Measure M15 through M19 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.

- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- Each Balancing Authority shall keep data or evidence for Requirement R22 and Measure M22 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.

- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

~~None.~~

~~Table of Compliance Elements~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Same-Day Operations, Real-time Operations~~	~~High~~	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	~~Same-Day Operations, Real-time Operations~~	~~High~~	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Operating Instructions.
R3	~~Same-Day Operations, Real-Time Operations~~	~~High~~	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	~~Same-Day Oper~~	~~High~~	N/A	N/A	N/A	The responsible entity did not inform

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~ations, Real-Time Operations~~					its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.
R5	~~Same-Day Operations, Real-time Operations~~	~~High~~	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety,

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						equipment, regulatory, or statutory requirements.
R6	~~Same-Day Operations, Real-Time Operations~~	~~High~~	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7			~~Real-Time Operations~~ N/A ~~High~~	N/A	N/A ~~N/A~~	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

~~For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	~~Operations Planning, Same-Day Operations, Real-Time Operations~~	~~High~~	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.			more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9	~~Operations Planning, Same-Day Operations,~~	~~Medium~~	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~Real-Time Operations~~		greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	assessment capabilities, or associated communication channels between the affected entities.	associated communication channels between the affected entities.	outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is

R #	~~Time Horizon~~	~~VRF~~		Lower VSL	Moderate VSL	High VSL	Severe VSL
							greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	~~Real-Time Operations~~	~~High~~	~~N/A~~	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the	The Transmission Operator did not monitor ~~one~~, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 ~~and did not obtain and utilize one of the items listed in~~	The Transmission Operator did not monitor ~~Facilities and the status of Special Protection Systems within its Transmission Operator Area and did not~~, obtain ~~and~~, or utilize ~~data deemed~~three of the items required or identified as necessary ~~from outside its~~by the Transmission Operator	The Transmission Operator did not monitor, obtain, or utilize four or more of the items

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Transmission Operator and listed in Requirement R10, Part 10.1~~.~~ ~~OR,~~ ~~The Transmission Operator did not obtain and utilize one of the items listed in Requirement R10, Part~~ through 10.~~2~~6.	~~Requirement R10, Part~~through 10.~~2.~~ 6.	~~Area~~and listed in Requirement R10, Part 10.1 through 10.6.	required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.
R11			~~Real-Time Operations~~N/A	~~High~~N/A ~~N/A~~ ~~N/A~~	The Balancing Authority did not monitor the status of ~~Special Protection Systems~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing

R #	~~Time Horizon~~	~~VRF~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Authority Area and support Interconnection frequency.
R12			~~Real-Time Operations~~ N/A	~~High~~N/A	N/A ~~N/A~~ ~~N/A~~	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	~~Same-Day Operations,~~	~~High~~	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~Real-Time Operations~~		was not conducted for one 30-minute period within that 24-hour period.			Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.			~~Real-Time Operations~~N/A	~~High~~N/A	N/A ~~N/A~~ ~~N/A~~	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels					
			Lower VSL	Moderate VSL	High VSL			Severe VSL
R15.			~~Real-Time Operations~~ N/A	N/A~~Medium~~	N/A	~~N/A~~	~~N/A~~	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.			~~Operations Planning, Same-Day Operations, Real-Time Operations~~ N/A	N/A~~High~~	N/A	~~N/A~~	~~N/A~~	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment,

R # ~~Time Horizon~~ ~~VRF~~	Violation Severity Levels					
	Lower VSL	Moderate VSL	High VSL			Severe VSL
						monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	~~Operations Planning, Same-Day Operations, Real-Time Operations~~ N/A	~~High~~ N/A	N/A	~~N/A~~	~~N/A~~	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						assessment capabilities, and associated communication channels between affected entities.
R18			~~Operations Planning, Same-Day Operations, Real-time Operations~~N/A	~~High~~N/A	N/A ~~N/A~~ ~~N/A~~	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	~~Operations Planning, Same-Day~~	~~High~~	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~Operations, Real-time Operations~~		Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	applicable entities, whichever is greater.		performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20			N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, as specified in the Requirement.	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						performing Real-time monitoring and Real-time Assessments as specified in the Requirement.
R21			The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test;

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.			OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
~~R20~~ R22	~~Operations Planning, Same-Day Operations, Real-time Oper~~	~~High~~	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or

R #	~~Time Horizon~~	~~VRF~~	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~ations~~					greater than 15% of the applicable entities, whichever is greater.
R23			N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, as specified in the Requirement.	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R24			The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.			capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						action within 8 hours to restore the redundant functionality.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

~~The~~The Implementation Plan and other project documents can be found on the project page.

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	February 9, 2017	Adopted by Board of Trustees	Revised

Guidelines and Technical Basis

None

Rationale~~:~~

During development of ~~this standard~~TOP-001-4, text boxes ~~were~~are embedded within the standard to explain the rationale for various parts of the standard. Upon ~~BOT approval~~Board adoption of TOP-001-4, the text from the rationale text boxes ~~was~~will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

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 Transmission Operator 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 the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20~~:~~ (R19, R20, R22, and R23 in TOP-001-4):

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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 Transmission Operator's (TOP) primary 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. 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'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. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R21:

The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for Requirements R22 and R23:

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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 Balancing Authority's (BA) primary 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. Requirement R23 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 BA'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. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R24:

The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component(e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Exhibit B

Implementation Plan

Implementation Plan

Project 2016-01 Modifications to TOP and IRO Standards
Reliability Standards IRO-002-5 and TOP-001-4

Applicable Standard(s)

- IRO-002-5 - Reliability Coordination - Monitoring and Analysis
- TOP-001-4 - Transmission Operations

Requested Retirement(s)

- IRO-002-4 - Reliability Coordination - Monitoring and Analysis
- TOP-001-3 - Transmission Operations

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

On November 19, 2015, the Federal Energy Regulatory Commission (FERC) issued Order No. 817 approving nine revised or new TOP and IRO Reliability Standards from Project 2014-03 that addressed previously-identified reliability issues and concerns. In approving the standards, FERC also directed development of modifications to TOP and IRO standards to address specific concerns related to: (i) Transmission Operator monitoring of some non-Bulk Electric System (non-BES) elements needed for reliable operations, and (ii) redundancy in data exchange capabilities used by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable operations.

General Considerations

The three-month implementation period for IRO-002-5 provides Reliability Coordinators with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality. The proposed implementation plan presumes that IRO-002-4 is effective, or will become effective, on or before the effective date of IRO-002-5.

The 12-month implementation period for TOP-001-4 provides Transmission Operators (TOP) with time to revise and distribute data specifications required by TOP-003-3 Requirement R1 to include non-BES data identified by the TOP, and receive data from entities responsible for providing the data as required by TOP-003-3 Requirement R5. The implementation period also provides TOPs and Balancing Authorities (BAs) with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality.

Effective Date

IRO-002-5
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-001-4
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

IRO-002-4
Reliability Standard IRO-002-4 shall be retired immediately prior to the effective date of IRO-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

TOP-001-3
Reliability Standard TOP-001-3 shall be retired immediately prior to the effective date of TOP-001-4 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

IRO-002-5
The initial test of primary Control Center data exchange capabilities specified in Requirement R3 must be completed within 90 calendar days of the effective date of IRO-002-5.

TOP-001-4
The initial test of primary Control Center data exchange capabilities specified in Requirements R21 and R24 must be completed within 90 calendar days of the effective date of TOP-001-4.

Exhibit D

Consideration of Directives

Order No. 817 Citation	Directive/Guidance	Resolution
P 35	Revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities.	The directive is addressed in proposed TOP-001-4 Requirement R10. Parts 10.3 and 10.6 cover non-BES facilities. ***Proposed TOP-001-4*** **R10.** Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.1.** Monitor Facilities within its Transmission Operator Area; **10.2.** Monitor the status of Remedial Action Schemes within its Transmission Operator Area; **10.3.** Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator; **10.4.** Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator; **10.5.** Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and **10.6.** Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

Order No. 817 Citation	Directive / Guidance	Resolution
P 47	Modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing. In addition, [the Commission directs] NERC to clarify that “redundant infrastructure” for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.	Proposed TOP-001-4 Requirements R20 and R23 address the directive for Transmission Operators (TOP) and Balancing Authorities (BA), respectively. For consistency, the Standards Drafting Team (SDT) developed proposed IRO-002-5 Requirement R2 to address the directive for Reliability Coordinators (RCs) rather than develop a modification to IRO-002-4 Requirement R4. ***Proposed TOP-001-4*** **R20.** Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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. **R23.** Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 analysis functions. ***Proposed IRO-002-5*** **R2.** Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators,

Order No. 817 Citation	Directive / Guidance	Resolution
		and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments.
P 51	Develop a modification to the TOP and IRO standards that 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.	The directive is addressed in proposed TOP-001-4 Requirements R21 and R24, and proposed IRO-002-5 Requirement R3. ***Proposed TOP-001-3*** **R21.** Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. **R24.** Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. ***Proposed IRO-002-5*** **R3.** Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality.

Exhibit E

Analysis of Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-01 - Modifications to TOP and IRO Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Reliability Standard requirements developed in Project 2016-01. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. 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.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

Project 2016-01 Reliability Standards Requirements

The SDT developed new or revised requirements in IRO-002-5 and TOP-001-4 to address reliability objectives outlined in the project Standard Authorization Request (SAR). The VRF and VSL justification for these new and revised requirements is described below. VRF and VSL justification for requirements that were not modified in Project 2016-01 can be found on the Project 2014-03 Project Page.

VRF Justification

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirement is not directly connected to an area identified in the Blackout Report.

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The proposed VRF is unchanged from approved TOP-001-3 Requirement R10. Additionally, the requirement is similar to approved IRO-002-4 Requirement R3 which applies to Reliability Coordinators and is assigned a High VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement addresses a single reliability objective and has a single VRF.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Operations Planning time horizon, which are not the subject of the Blackout Report recommendations regarding data exchange. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements address data exchange capabilities for the Operations Planning time horizon only, which is a significant change from approved IRO-002-4 Requirement R1 and TOP-001-3 Requirements R19 and R20 which apply to all operations time horizons. As proposed, the VRF will establish consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a Medium VRF. Failure to have data exchange capabilities necessary for performing Operational Planning Analysis or for developing an Operating Plan for next day operations could directly and adversely affect the electrical state or capability of the BES, or the ability to effectively control or restore the BES. However, this failure is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
Proposed VRF	High
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Same-day Operations and Real-time Operations time horizons. A High VSL is assigned to reflect the potential impact on the reliability of the BES consistent with the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements improve upon requirements for data exchange capabilities in approved IRO-002-4 and TOP-001-3, which are assigned a High VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a High VRF. Failure to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the primary Control Center, for performing Real-time monitoring and analysis could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
Proposed VRF	Medium
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements are not directly connected to an area identified in the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	These are new requirements. Approved COM-001-2.1 Requirement R9 requires periodic testing of Alternate Interpersonal Communications capability and is assigned a Medium VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5, proposed TOP-001-4, and approved COM-001-2.1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for Medium VRF. Failure to periodically test primary Control Center data exchange capabilities for redundant functionality could, under anticipated data exchange infrastructure failure, affect the ability to monitor and control the BES. However, failure to test primary Control Center data exchange capabilities for redundant functionality is not likely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VSL Justification

VSLs for TOP-001-4 Requirement R10			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

VSL Justifications for TOP-001-4 Requirement R10	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved TOP-001-3 Requirement R10.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for TOP-001-4 Requirement R10	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22			
Lower	**Moderate**	**High**	**Severe**
The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with one identified entity, or 5% or less of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with two identified entities, or more than 5% or less than or equal to 10% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with three identified entities, or more than 10% or less than or equal to 15% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with four or more identified entities or greater than 15% of the identified entities, whichever is greater.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved IRO-002-4 Requirement R1 and approved TOP-001-3 Requirements R19 and R20.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The applicable entity had data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), but did not have redundant and diversely routed data exchange infrastructure	The applicable entity did not have data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), as specified in the Requirement.

		within its primary Control Center, as specified in the Requirement.	

VSL Justifications for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24			
Lower	**Moderate**	**High**	**Severe**
The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 180 calendar days since the previous test; OR The applicable entity did not test its primary Control Center data exchange capabilities for redundant functionality; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

Exhibit F

Summary of Development History and Complete Record of Development

Summary of Development History

Summary of Development History

The development record for proposed Reliability Standards IRO-002-5 and TOP-001-4 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team selected to lead each project in accordance with Section 4.3 of the NERC Standards Process Manual.[2] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit G.

II. Standard Development History

A. Standard Authorization Request Development

Project 2016-01 – Modifications to TOP and IRO Standards was initiated on January 6, 2016 as a Standards Authorization Request ("SAR") to address Commission directives in Order No. 817.[3] In Order No. 817, the Commission direct[ed] NERC to make three modifications to the TOP and IRO Reliability Standards.[4] The SAR was posted for a 30-day informal comment period from January 22, 2016 through February 22, 2016 and was accepted by the Standards Committee on June 15, 2016.

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2012).

2 The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

3 Order No. 817, *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards* 153 FERC ¶ 61,178, 80 Fed. Reg. 73977 (2015).

4 *Id*.

B. First Posting - Comment Period, Initial Ballots and Non-Binding Polls

Proposed Reliability Standards IRO-002-5 and TOP-001-4 were posted for a 45-day formal comment period from June 20, 2016 through August 3, 2016, with parallel Initial Ballots and Non-binding Polls held during the last 10 days of the comment period from July 25, 2016 through August 3, 2016. Several documents were posted for guidance with the first draft, including the Unofficial Comment Form, the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") Justification document, and the Consideration of Directives document. The Initial Ballot for IRO-002-5 received 84.50% quorum, and 67.25% approval. The Initial Ballot for TOP-001-4 received 85.81% quorum, and 64.59% approval. The Non-binding Poll for IRO-002-5 received 84.05% quorum and 64.05% of supportive opinions. The Non-binding Poll for TOP-001-4 received 84.17% quorum and 65.43% of supportive opinions. There were 58 sets of responses, including comments from approximately 156 different individuals and approximately 76 companies, representing all 10 of the industry segments.[5]

C. Second Posting- Comment Period, Additional Ballots and Non-Binding Polls

Proposed Reliability Standards IRO-002-5 and TOP-001-4 were posted for a 45-day formal comment period from August 31, 2016 through October 17, 2016, with parallel Additional Ballots and Non-binding Polls held during the last 10 days of the comment period from October 5, 2016 through October 17, 2016.[6] The Additional Ballot for IRO-002-5 reached quorum at 83.64% of the ballot pool, and received 70.77% approval. The Additional Ballot for TOP-001-4 reached quorum at 82.06% of the ballot pool, and received 68.85% approval. The

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[5] NERC, *Consideration of Comments*, Project 2016-01 Modifications to TOP and IRO Standards, (August 31, 2016), *available at* http://www.nerc.com/pa/Stand/Project%20201601%20Modifications%20to%20TOP%20and%20IRO%20Standa/2016-01_TOP_IRO_Consideration%20of%20Comments08252016.pdf.

[6] The Ballots, Non-binding Polls, and Comment Period were extended an additional day from October 14, 2016 to reach quorum.

related Non-Binding Poll for IRO-002-5 reached quorum at 81.96% of the ballot pool, and 68.67% of supportive opinions. The related Non-Binding Poll for TOP-001-4 reached quorum at 80.80% of the ballot pool, with 67.98% of supportive opinions. There were 37 sets of responses, including comments from approximately 118 different individuals and approximately 91 companies, representing all 10 of the industry segments.[7]

D. Final Ballot

Proposed Reliability Standards IRO-002-5 and TOP-001-4 were posted for a 10-final ballot period from December 2, 2016 through December 12, 2016. The ballot for proposed Reliability Standard IRO-002-5 and associated documents reached quorum at 91.08% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 74.30% of the voters. The ballot for proposed Reliability Standard TOP-001-4 and associated documents reached quorum at 90.70% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 72.52% of the voters.

E. Board of Trustees Adoption

Proposed Reliability Standards IRO-002-5 and TOP-001-4 were adopted by the NERC Board of Trustees on February 9, 2017.[8]

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[7] NERC, *Consideration of Comments*, Project 2016-01 Modifications to TOP and IRO Standards, (December 1, 2016), *available at* http://www.nerc.com/pa/Stand/Project%20201601%20Modifications%20to%20TOP%20and%20IRO%20Standa/2016-01_TOP_IRO_Consideration_of_comments_12022016.pdf.

[8] NERC, *Board of Trustees Agenda Package*, Agenda Item 4a (Project 2016-01 Modifications to TOP and IRO Standards (IRO-002-5, TOP-001-4)), *available at* http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_February_9_2017_Meeting_Agenda_Package_v3.pdf.

Complete Record of Development

Project 2016-01 Modifications to TOP and IRO Standards

Related Files

Status
Final ballots for **IRO-002-5 - Reliability Coordination - Monitoring and Analysis** and **TOP-001-4 - Transmission Operations** concluded **8 p.m. Eastern, Monday, December 12, 2016**. The voting results can be accessed via the links below. The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background
On November 19, 2015, the Federal Energy Regulatory Commission (Commission) issued Order No. 817 approving nine TOP and IRO standards from Project 2014-03 and retiring or superseding 18 currently-enforceable standards. The proposed standards were developed in Project 2014-03 to address Commission concerns and reliability issues identified in the 2011 Southwest Outage Report, the Independent Experts Review Panel project, and stakeholder technical conferences. In approving the new TOP and IRO standards, the Commission issued three directives to modify the TOP and IRO standards to address additional reliability issues.

Standard(s) Affected – The Standard Drafting Team (SDT) will develop modifications to **TOP-001-3 - Transmission Operations** and **IRO-002-4 - Reliability Coordination: Monitoring and Analysis** to address Order No. 817 directives, or develop an equally efficient and effective alternative.

Purpose/Industry Need
The modifications to TOP and IRO standards developed in this project will address the following reliability concerns identified in Order No. 817:

- **Monitoring non-Bulk Electric System facilities.** The Commission noted that "in some instances the absence of real-time monitoring of non-BES facilities by the transmission operator within and outside its TOP area as necessary for determining SOL exceedances in proposed TOP-001-3, Requirement R10 creates a reliability gap." (P.35)
- **Redundancy and Diverse Routing of Data Exchange Capabilities.** The Commission determined that, with respect to data exchange capabilities, the TOP and IRO standards requirements for Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) "do not clearly address redundancy and diverse routing so that registered entities will unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations." (P. 47)
- **Testing of the Alternate or Less Frequently Used Data Exchange Capability.** The Commission determined that existing requirements do not establish a clear obligation for RCs, TOPs, and BAs to test alternative data exchange capabilities (P. 51).

Per Order No. 817, revised Reliability Standards addressing these issues must be filed for approval by July 2017.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft IRO-002-5 Clean **(46)** | Redline to Last Posted **(47)**| Redline to Last Approved **(48)** TOP-001-4 Clean **(49)** | Redline to Last Posted **(50)** | Redline to Last Approved **(51)** Implementation Plan Clean **(52)** | Redline to Last Posted **(53)** **Supporting Materials** VRF/VSL Justification Clean **(54)** | Redline to Last Posted **(55)**	Final Ballots Info **(56)** Vote	12/02/16 - 12/12/16	Ballot Results IRO-002-5 **(57)** TOP-001-4 **(58)**	
Draft 2 IRO-002-5 Clean **(25)** | Redline to Last Posted **(26)** | Redline to Last Approved **(27)** TOP-001-4 Clean **(28)** | Redline to Last Posted **(29)** | Redline to Last Approved **(30)** Implementation Plan Clean **(31)** | Redline to Last Posted **(32)** **Supporting Materials**	Additional Ballots and Non-binding Polls Updated Info **(37)** Info **(38)** Vote	10/05/16 - 10/17/16 The Ballots, Non-binding Polls, and Comment Period were extended an additional day (from 10/14/16) to reach quorum	Ballot Results IRO-002-5 **(39)** TOP-001-4 **(40)** Non-binding Polls IRO-002-5 **(41)** TOP-001-4 **(42)**	
Unofficial Comment Form (Word) **(33)** VRF/VSL Justification Clean **(34)** | Redline to Last Posted **(35)** Consideration of Directives **(36)**	Comment Period Info **(43)** Submit Comments	08/31/16 - 10/17/16	Comments Received **(44)**	Consideration of Comments **(45)**
Draft Reliability Standard Audit Worksheets (RSAWs) IRO-002-5 TOP-001-4	Info Send RSAW feedback to: RSAWfeedback@nerc.net	09/12/16 - 10/17/16		

Draft 1 IRO-002-5 Clean **(8)** | Redline to last approved **(9)** TOP-001-4 Clean **(10)** | Redline to last approved **(11)** Implementation Plan **(12)**	Initial Ballots and Non-binding Polls Updated Info **(16)** Info **(17)** Vote	07/25/16 - 08/03/16	Ballot Results IRO-002-5 **(18)** TOP-001-4 **(19)** Non-binding Poll Results IRO-002-5 **(20)** TOP-001-4 **(21)**	
Supporting Materials Unofficial Comment Form (Word) **(13)** VRF/VSL Justification **(14)** Consideration of Directives **(15)**	Comment Period Info **(22)** Submit Comments	06/20/16 - 08/03/16	Comments Received **(23)**	Consideration of Comments **(24)**
	Join Ballot Pools	06/20/16 - 07/19/16		
Draft Reliability Standard Audit Worksheets (RSAWs) IRO-002-5 TOP-001-4	Info Send RSAW feedback to: RSAWfeedback@nerc.net	07/01/16 - 08/03/16		
The Standards Committee accepted the Standards Authorization Request on June 15, 2016				
Standards Authorization Request **(3)** **Supporting Materials** Unofficial Comment Form (Word) **(4)**	Comment Period Info **(5)** Submit Comments	01/22/16 - 02/22/16	Comments Received **(6)**	Consideration of Comments **(7)**
Standard Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(1)**	Nomination Period Info **(2)** Submit Nominations	01/22/16 - 02/04/16		

Unofficial Nomination Form

Project 2016-01 Modifications to TOP and IRO Standards

Solicitation for Standard Drafting Team (SDT) Nominations

DO NOT use this form for submitting nominations. The electronic form should be used to submit nominations prior to **8 p.m. Eastern, Thursday, February 4, 2016.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form. If you have any questions, contact Senior Standards Developer, Mark Olson (via email) or by telephone at (404) 446-9760.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the standard drafting team (SDT) meetings if appointed by the Standards Committee. If appointed, you are expected to attend most of the face-to-face meetings as well as participate in the meetings held via conference calls.

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the SDT sets forth. Review and drafting teams also may have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the SDT effort is outreach. Members of the team should be conducting outreach during development prior to posting to ensure all issues can be addressed.

Background

On November 19, 2015, the Federal Energy Regulatory Commission (Commission) issued Order No. 817 approving nine TOP and IRO standards from Project 2014-03 and retiring or superseding 18 currently-enforceable standards. The proposed standards were developed in Project 2014-03 to address Commission concerns and reliability issues identified in the 2011 Southwest Outage Report, the Independent Experts Review Panel project, and stakeholder technical conferences. In approving the new TOP and IRO standards, the Commission issued three directives to modify the TOP and IRO standards to address additional reliability issues.

As described in the SAR, the SDT for this project will develop modifications to **TOP-001-3 - Transmission Operations** and **IRO-002-4 - Reliability Coordination: Monitoring and Analysis** to address Order No. 817 directives, or develop an equally efficient and effective alternative.

The modifications to TOP and IRO standards developed in this project will address the following reliability concerns identified in Order No. 817:

- **Monitoring non-Bulk Electric System facilities.** The Commission noted that "in some instances the absence of real-time monitoring of non-BES facilities by the transmission operator within and outside its TOP area as necessary for determining SOL exceedances in proposed TOP-001-3, Requirement R10 creates a reliability gap." (P.35)

- **Redundancy and Diverse Routing of Data Exchange Capabilities.** The Commission determined that, with respect to data exchange capabilities, the TOP and IRO standards requirements for Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) "do not clearly address redundancy and diverse routing so that registered entities will unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations." (P. 47)
- **Testing of the Alternate or Less Frequently Used Data Exchange Capability.** The Commission determined that existing requirements do not establish a clear obligation for RCs, TOPs, and BAs to test alternative data exchange capabilities (P. 51).

Per Order No. 817, revised Reliability Standards addressing these issues must be filed for approval by July 2017.

Please provide the following information for the nominee:	
Name:	
Title:	
Organization:	
Address:	
Telephone:	
Email:	

Please briefly describe the nominee's experience and qualifications to serve on the selected project(s):

If you are currently a member of any NERC SAR or standard drafting team, please list each team here:

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC SAR or standard drafting team, please identify the team(s):

☐ No prior NERC SAR or standard drafting team.

☐ Prior experience on the following SAR or standard drafting team(s):

Select each NERC Region in which you have experience relevant to Project 2009-02:		
☐ TEXAS RE	☐ NPCC	☐ SPP RE
☐ FRCC	☐ RF	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	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, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:

☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:

Name:		Telephone:	
Organization:		Email:	
Name:		Telephone:	
Organization:		Email:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the names and contact information of your immediate supervisor or a member of your management who can confirm your organization’s willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2016-01 Modifications to TOP and IRO Standards

Standard Drafting Team Nomination Period Open through February 4, 2016

Now Available

Nominations are being sought for standard drafting team (SDT) members through **8 p.m. Eastern, Thursday, February 4, 2016**.

Use the electronic form to submit a nomination. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the SDT meetings if appointed by the Standards Committee. If appointed, you are expected to attend most of the face-to-face meetings as well as participate in the meetings held via conference calls.

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the SDT sets forth. Review and drafting teams also may have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the SDT effort is outreach. Members of the team should be conducting outreach during development prior to posting to ensure all issues can be addressed.

Next Steps

The Standards Committee is expected to appoint members to the team in March 2016. Nominees will be notified shortly after they have been appointed.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760..

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Modifications to TOP and IRO Standards		
Date Submitted:	January 6, 2016		
SAR Requester Information			
Name:	Ryan Stewart		
Organization:	NERC		
Telephone:	404-446-9712	E-mail:	Ryan.Stewart@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
The goal of this project is to address the Federal Energy Regulatory Commission (Commission) directives contained in Order 817 by modifying **TOP-001-3 - Transmission Operations** and **IRO-002-4 - Reliability Coordination: Monitoring and Analysis** or by developing an equally efficient and effective alternative.
Industry Need (What is the industry problem this request is trying to solve?):
On November 19, 2015, the Commission issued Order 817 approving nine revised or new TOP and IRO Reliability Standards from Project 2014-03 that addressed previously-identified reliability issues and concerns. In approving the standards, the Commission also directed development of modifications to TOP and IRO standards to address the following additional reliability concerns: • **Monitoring non-Bulk Electric System facilities.** The Commission noted that "in some instances the absence of real-time monitoring of non-BES facilities by the transmission operator within

SAR Information
and outside its TOP area as necessary for determining SOL exceedances in proposed TOP-001-3, Requirement R10 creates a reliability gap." (P.35) • **Redundancy and Diverse Routing of Data Exchange Capabilities.** The Commission determined that, with respect to data exchange capabilities, the TOP and IRO standards requirements for Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) "do not clearly address redundancy and diverse routing so that registered entities will unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations." (P. 47) • **Testing of the Alternate or Less Frequently Used Data Exchange Capability.** The Commission determined that existing requirements do not establish a clear obligation for RCs, TOPs, and BAs to test alternative data exchange capabilities (P. 51). Per Order 817, revised Reliability Standards addressing these issues must be filed for approval within 18 months of the order effective date.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standards Drafting Team (SDT) shall develop modifications to TOP and IRO standards that address Commission directives from Order 817. The work will include development of Violation Risk Factors, Violation Severity Levels, and an Implementation Plan for the modified standards within the deadline established by the Commission in Order 817.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDT shall address each of the Order 817 directives by developing modifications to requirements in TOP-001-3 and IRO-002-4, or the SDT shall develop an equally efficient and effective alternative. To address concerns identified in Order 817, the Commission directed the following: • *Revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities. [The Commission] believes this is best accomplished by adopting language similar to Reliability Standard IRO-002-4, Requirement R3, which requires reliability coordinators to monitor non-bulk electric system facilities to the extent necessary. NERC can develop an equally efficient and effective alternative that addresses our concerns. (P. 35)* • *Modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing. In addition, [the Commission directs] NERC to clarify that “redundant infrastructure” for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities. (P. 47)*

SAR Information
• *Develop a modification to the TOP and IRO standards that 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. [The Commission believes] that the structure of Reliability Standard COM-001-2, Requirement R9 could be a model for use in the TOP and IRO Standards. (P. 51)*

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).

Reliability Functions		
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Reliability and Market Interface Principles	
Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	YES

Related Standards	
Standard No.	Explanation
IRO-002-4	Includes requirements for RC data exchange capabilities and monitoring systems
TOP-001-3	Includes requirements for TOP Real-time monitoring, and for TOP and BA data exchange capabilities

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
FRCC	
MRO	

Regional Variances	
NPCC	
RF	
SERC	
SPP RE	
Texas RE	
WECC	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2016-01 Modifications to TOP and IRO Standards
Standards Authorization Request

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the Standards Authorization Request (SAR) developed by NERC Staff. The electronic comment form must be completed and submitted by **8:00 p.m. Eastern, Monday, February 22, 2016**.

Documents and information about this project are available on the project page. If you have any questions, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

Background Information

On November 19, 2015, the Federal Energy Regulatory Commission (Commission) issued Order No. 817 approving nine TOP and IRO standards from Project 2014-03 and retiring or superseding 18 currently-enforceable standards. The proposed standards were developed in Project 2014-03 to address Commission concerns and reliability issues identified in the 2011 Southwest Outage Report, the Independent Experts Review Panel project, and stakeholder technical conferences. In approving the new TOP and IRO standards, the Commission issued three directives to modify the TOP and IRO standards to address additional reliability issues.

As described in the SAR, the Standard Drafting Team (SDT) for this project will develop modifications to **TOP-001-3 - Transmission Operations** and **IRO-002-4 - Reliability Coordination: Monitoring and Analysis** to address Order No. 817 directives, or develop an equally efficient and effective alternative.

The modifications to TOP and IRO standards developed in this project will address the following reliability concerns identified in Order No. 817:

- **Monitoring non-Bulk Electric System facilities.** The Commission noted that "in some instances the absence of real-time monitoring of non-BES facilities by the transmission operator within and outside its TOP area as necessary for determining SOL exceedances in proposed TOP-001-3, Requirement R10 creates a reliability gap." (P.35)
- **Redundancy and Diverse Routing of Data Exchange Capabilities.** The Commission determined that, with respect to data exchange capabilities, the TOP and IRO standards requirements for Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) "do not clearly address redundancy and diverse routing so that registered entities will unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations." (P. 47)
- **Testing of the Alternate or Less Frequently Used Data Exchange Capability.** The Commission determined that existing requirements do not establish a clear obligation for RCs, TOPs, and BAs to test alternative data exchange capabilities (P. 51).

Per Order No. 817, revised Reliability Standards addressing these issues must be filed for approval by July 2017.

Questions

1. Do you agree with the proposed scope for Project 2016-01 as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

☐ Yes
☐ No
Comments:

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

Comments:

Standards Announcement

Project 2016-01 Modifications to TOP and IRO Standards
Standard Authorization Request

Comment Period Open through February 22, 2016

Now Available

An informal comment period for the **Project 2016-01 Modifications to TOP and IRO Standards** Standards Authorization Request (SAR), is open through **8 p.m. Eastern, Monday, February 22, 2016**.

Commenting

Use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the Standards Balloting & Commenting System due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The drafting team will consider all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2016-01 Modifications to TOP and IRO Standards SAR
Comment Period Start Date:	1/22/2016
Comment Period End Date:	2/22/2016
Associated Ballots:	

There were 22 sets of responses, including comments from approximately 22 different people from approximately 21 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed scope for Project 2016-01 as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Ben Engelby	6		ACES Standards Collaborators - TOP/IRO Project	Chip Koloini	ACES Power Marketing	3,5	SPP RE
					Bob Solomon	ACES Power Marketing	1	RF
					Shari Heino	ACES Power Marketing	1,5	Texas RE
					Mike Brytowski	ACES Power Marketing	1,3,5,6	MRO
					Ginger Mercier	ACES Power Marketing	1,3	SERC
					Ellen Watkins	ACES Power Marketing	1	SPP RE
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	MRO	3,4,5,6	MRO
					Chuck Lawrence	MRO	1	MRO
					Chuck Wicklund	MRO	1,3,5	MRO
					Dave Rudolph	MRO	1,3,5,6	MRO
					Kayleigh Wilkerson	MRO	1,3,5,6	MRO
					Jodi Jenson	MRO	1,6	MRO
					Larry Heckert	MRO	4	MRO
					Mahmood Safi	MRO	1,3,5,6	MRO
					Shannon Weaver	MRO	2	MRO
					Mike Brytowski	MRO	1,3,5,6	MRO
					Brad Perrett	MRO	1,5	MRO
					Scott Nickels	MRO	4	MRO
					Terry Harbour	MRO	1,3,5,6	MRO
					Tom Breene	MRO	3,4,5,6	MRO
					Tony Eddleman	MRO	1,3,5	MRO
					Amy Casucelli	MRO	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

Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	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
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	New York Independent System Operator	2	NPCC
					Ben Li	New York Independent System Operator	2	NPCC
					Kathleen Goodman	New York Independent System Operator	2	NPCC
					Mark Holman	New York Independent System Operator	2	NPCC
					Charles Yeung	New York Independent System Operator	2	SPP RE
					Terry Bilke	New York Independent System Operator	2	MRO
					Nathan Bigbee	New York Independent System Operator	2	Texas RE
					Ali Miremadi	New York Independent System Operator	2	WECC
Dominion - Dominion Resources, Inc.	Randi Heise	3,5,6		Dominion - RCS	Larry Nash	Dominion - Dominion Resources, Inc.	1	SERC

Dominion - Dominion Resources, Inc.	Randi Heise	3,5,6		Dominion - RCS	Louis Slade	Dominion - Dominion Resources, Inc.	6	SERC
					Connie Lowe	Dominion - Dominion Resources, Inc.	3	RF
					Randi Heise	Dominion - Dominion Resources, Inc.	5	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no ISO-NE HQ and NextEra	Paul Malozewski	Northeast Power Coordinating Council	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Brian Shanahan	Northeast Power Coordinating Council	1	NPCC
					Rob Vance	Northeast Power Coordinating Council	1	NPCC
					Mark J. Kenny	Northeast Power Coordinating Council	1	NPCC
					Gregory A. Campoli	Northeast Power Coordinating Council	2	NPCC
					Randy MacDonald	Northeast Power Coordinating Council	2	NPCC
					Wayne Sipperly	Northeast Power Coordinating Council	4	NPCC
					David Ramkalawan	Northeast Power Coordinating Council	4	NPCC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no ISO-NE HQ and NextEra	Glen Smith	Northeast Power Coordinating Council	4	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
					Brian Robinson	Northeast Power Coordinating Council	5	NPCC
					Bruce Metruck	Northeast Power Coordinating Council	6	NPCC
					Alan Adamson	Northeast Power Coordinating Council	7	NPCC
					Michael Jones	Northeast Power Coordinating Council	3	NPCC
					Michael Forte	Northeast Power Coordinating Council	1	NPCC
					Kelly Silver	Northeast Power Coordinating Council	3	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
					Robert J Pellegrini	Northeast Power Coordinating Council	1	NPCC
					Edward Bedder	Northeast Power Coordinating Council	1	NPCC
					David Burke	Northeast Power Coordinating Council	3	NPCC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no ISO-NE HQ and NextEra	Peter Yost	Northeast Power Coordinating Council	4	NPCC
					Helen Lainis	Northeast Power Coordinating Council	2	NPCC
					Connie Lowe	Northeast Power Coordinating Council	4	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Jason Smith	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Jim Nail	Southwest Power Pool, Inc. (RTO)	3,5	SPP RE
					J. Scott Williams	Southwest Power Pool, Inc. (RTO)	1,4	SPP RE
					Kevin Giles	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP RE
					Ellen Watkins	Southwest Power Pool, Inc. (RTO)	1	SPP RE
					Sing Tay	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP RE
					John Allen	Southwest Power Pool, Inc. (RTO)	1,4	SPP RE
					Mike Kidwell	Southwest Power Pool, Inc. (RTO)	1,3,5	SPP RE
					Don Schmit	Southwest Power Pool, Inc. (RTO)	1,3,5	MRO

1. Do you agree with the proposed scope for Project 2016-01 as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Thomas Foltz - AEP - 3,5	
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 believe a more prudent approach would be to focus on the desired end state itself. We believe the argument can be made that our existing obligations, when considered as a whole, could collectively appease FERC's concerns.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

We have no concern with the Commission's directive that there should be some additional language in reference to TOP-001-3 Requirement R10. Also, we agree that IRO-002-4 Requirement R3 can serve as a foundation for that particular language. We also suggest that the drafting team follow the Functional Model Advisory Group's efforts very closely so that any clarified functional obligations are captured and consistent with the Functional Model. Additionally, we would suggest the drafting team to clarify that the non-BES facilities that the TOP is required to monitor be only those facilities that were identified by the Reliability Coordinator in IRO-002-4.

As for the Commission's suggestion of adding clarity to the term 'redundant infrastructure', our review group suggests the SDT consider developing a Standards Authorization Request (SAR) to create a definition for this particular term that can be added to the NERC Glossary, Rules of Procedure, and Functional Model. When the term "Alternative Interpersonal Communication" was created as a part of COM-001-2, the SDT included within the definition that the capability must use a different infrastructure. The definition of 'redundant infrastructure' could include the requirement to be diversely routed.

We don't feel it is appropriate to have a blanket requirement for the TOP to be required to have fully redundant data exchange capabilities with each entity it has identified it needs data from. The Transmission Operator may only receive a handful of points from certain entities, and there may be minimal impact to reliability if that data was lost. Any new requirement or change to R19 and R20 should provide the Transmission Operator the ability to identify and declare the entities with which it needs to have fully redundant and diversely routed data exchange capability.

In addition to the directives by FERC to modify the TOP and IRO standards, we suggest that the SDT review the use of the term 'Operating Instruction' as found in the TOP and IRO standards. It appears that the COM-002-4 Drafting Team did not intend to do a direct replacement of the term 'Directive' with 'Operating Instruction'. However, it appears the TOP-001-3 R3 and R4 are zero tolerance on compliance with EACH Operating Instruction. Previously the wording in the Standards required zero tolerance on the receipt of Directives. The definition of Operating Instruction is much broader and can be interpreted to include some system to system communications that were not previously considered to be Directives. We do not believe the intent of the term Operating Instruction in TOP-001-3 is consistent with the definition and use of the term in COM-002-4.

Likes 0	
Dislikes 0	

Response

Joshua Smith - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

The suggested revision of approved NERC Standard TOP-001-3, specifically Requirement 10, to require real-time monitoring of non-BES facilities is not needed and is already covered by the existing language. Requirement 10.1 states; "Within its Transmission Area, monitor facilities and the status of Special Protection Systems, and". R10.1 requires TOPs to monitor facilities to determine SOL exceedances, which allows the TOP to decide which "Facilities" it deems neccessary to meet the task required by R10. By adding the requirement to real-time monitor non-BES facilities, the Standard requires how something should be done instead of stating what is required and allowing the utility to decide how.

Likes 0	
Dislikes 0	

Response

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Answer	No
Document Name	
Comment	

Florida Power and Light (FPL) appreciates the efforts of NERC drafting a SAR proposing changes to TOP-001-3 and IRO-002-4 to address concerns expressed during the FRCC Order No. 817. For the three specific concerns mentioned, Monitoring non-Bulk Electric Systems facilities, FPL believes the new TOP-001-3 standard and the BES definition addresses this concern and do not feel a standard revision is necessary. In the case of Redundancy and Diverse Routing of Data Exchange Capabilities, FPL believes the revised TOP and IRO standards adequately address redundancy and diverse routing of data exchange capabilities and do not feel additional standard revisions are necessary. Lastly, in the testing of the Alternative or Less Frequently Used Data Exchange Capability, FPL believes RCs, TOPs and BAs should have protocols to ensure their alternative data exchange capabilities are viable in order to comply with the revised TOP and IRO standards and in good utility practice; and do not feel additional standard requirements are necessary.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	Project 2016-01 IRO_TOP SAR comments City Light 2016 Feb 18.dotx
Comment	

See attached document

Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	
Comment	

ERCOT joins in the comments of the IRC Standards Review Committee (SRC).

The SRC agrees that a drafting team needs to address the directives issued by FERC in Order No 817.

Likes 0	
Dislikes 0	
Response	

William Temple - PJM Interconnection, L.L.C. - 2 - RF	
Answer	Yes
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
: The SRC agrees that a drafting team needs to address the directives issued by FERC in Order No 817.	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - TOP/IRO Project	
Answer	Yes
Document Name	
Comment	
We agree that the scope of the SAR is drafted to address the FERC directives in Order No. 817. We ask the SDT to strongly consider cost implications and to explore equally efficient and effective alternatives to developing additional requirements. Such alternatives could include glossary term revisions, identifying existing standards that already address the directive, or the development of a reliability guideline.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
The SDT directive to “revise TOP-001-3 R10 to require real-time monitoring of non-BES facilities” needs to be developed using clear criteria delineating when monitoring is required and what approach or parameters would constitute adequate monitoring.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Kenny - Eversource Energy - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jamison Dye - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE HQ and NextEra	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE HQ and NextEra	
Answer	
Document Name	
Comment	
The SAR should allow the SDT to explain the meaning of "diverse routing" and "redundancy". A glossary term may not be needed but an explanation of the intent will be required to facilitate compliance. Also, as a general comment, FERC wanted to limit "redundancy and diversity" to data exchange between RC, TOP and BA so the SDT will need to avoid capturing other entities like TO and DP into this requirement.	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - TOP/IRO Project	
Answer	
Document Name	
Comment	
1. We recommend that the SDT conduct a technical conference relating to this project to explore any equally efficient and effective alternatives in lieu of modifying the existing standards. This would allow industry an opportunity to provide initial feedback prior to any proposed standard revisions. We also recommend that if the SDT agrees with this approach, that it considers broadcasting the technical conference via a webinar for industry stakeholders who are unable to attend in person. A recent technical conference held for NERC Project 2007-06.2 was limited to 20 people and was not open to a large majority of industry to attend. 2. For TOP-001-3 R10, we have concerns with the proposal of expanding the TOP's responsibilities for monitoring non-BES facilities. The SDT could consider alternatives including references to the existing BES exception process or the development of a reliability guideline. In the event that the SDT decides to pursue development of the requirement instead of identifying an alternative, we recommend limiting the scope of monitoring non-BES facilities to only the facilities that were identified by the Reliability Coordinator in IRO-002-4 and agreed to by the Transmission Operator. 3. For TOP-001-3 R19 and R20 relating to "redundant infrastructure," the SDT should consider developing a formal glossary term to provide clarity for the requirements. Cost considerations should also be factored into the development of these requirements. 4. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	

Comment	
The SRC would like NERC and the drafting team to consider alternatives to a reliability standard to address the directives included in the Order. The types of activities contemplated in the SAR are upstream and act as controls around registered entities performing core reliability functions, such as responding to IROL's or developing emergency plans. Redundant and diversely routed data exchange capabilities, in addition to testing of alternate or less frequently used data exchange capabilities are not core reliability requirements. Moreover, given the relatively static nature of these types of activities (e.g., establishing communications equipment), RC/BA/TOP Certification is a more appropriate program for the ERO to use to support reliable operations than auditing. Also, the SRC would like the drafting team to consider clarifying "redundant and diversely routed data exchange capabilities". The SRC asks the SDT to consider whether data that goes to two independent control sites satisfy the concepts of redundant and diversely routed or does the SDT intend to require two independent feeds to each cite? The SRC would also like the SDT to consider the applicability of non-BES Elements to the standards process. NERC is close to implementing an improved BES Definition on July 1, 2016, that will provide greater clarity to facilities that will impact the interconnected transmission system. The SDT should consider how this definition can capture elements that may not meet the core BES definition but should be BES going forward.	
Likes 0	
Dislikes 0	
Response	
Joshua Smith - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
TOP-001-3 R10 as proposed requires each TOP shall monitor Facilities and the status of SPSs within its TOP area and obtain and utilize status, voltages and flow data for facilities and status of SPS outside its TOP area. The ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001-3 does it require TOs to supply neighboring TOs with this data. Oncor requests R10 be reworded to provide flexibility for region structure.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT joins in the comments of the IRC Standards Review Committee (SRC).

The SRC would like NERC and the drafting team to consider alternatives to a reliability standard to address the directives included in the Order. The types of activities contemplated in the SAR are upstream and act as controls around registered entities performing core reliability functions, such as responding to IROL's or developing emergency plans. Redundant and diversely routed data exchange capabilities, in addition to testing of alternate or less frequently used data exchange capabilities are not core reliability requirements. Moreover, given the relatively static nature of these types of activities (e.g., establishing communications equipment), RC/BA/TOP Certification is a more appropriate program for the ERO to use to support reliable operations than auditing.

Also, the SRC would like the drafting team to consider clarifying "redundant and diversely routed data exchange capabilities". The SRC asks the SDT to consider whether data that goes to two independent control sites satisfy the concepts of redundant and diversely routed or does the SDT intend to require two independent feeds for each data sample to each site?

The SRC would also like the SDT to consider the applicability of non-BES Elements to the standards process. NERC is close to implementing an improved BES Definition on July 1, 2016, that will provide greater clarity to facilities that will impact the interconnected transmission system. The SDT should consider how this definition can capture elements that may not meet the core BES definition but should be BES going forward.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 3,5

Answer	
Document Name	

Comment

Though the directives given by FERC potentially impact the same standard(s), and the"identification of non-BES elements" and "redundant data exchange capabilities"emanate from the same FERC Order, the topics appear disparate enough to drive two separate projects. Would it be preferable to create two separate project teams to pursue the FERC directives, rather than combine multiple, dissimilar directives into a single project?

Likes 0	
Dislikes 0	

Response

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

Answer	

Document Name	
Comment	
See attached document from 1	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
Per section 47 of FERC Order 817, recommend adding Reliability Standards IRO-002-4, Requirement R4 to clarify what “redundant infrastructure” is, within this SAR.	
Likes 0	
Dislikes 0	
Response	

Per Order No. 817, revised Reliability Standards addressing these issues must be filed for approval by July 2017.

Questions

1. Do you agree with the proposed scope for Project 2016-01 as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

☒ Yes
☐ No
Comments:

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

Comments:
Duke Energy has several thoughts regarding this project we would like to relay to the drafting team.

-Regarding redundancy and diverse routing of data exchange capabilities, Duke Energy requests that the drafting team clearly define what is meant by “data exchange capabilities”. This terminology seems rather vague at this point, and could use an adequate definition to clear up any possible ambiguity. Also, previously a requirement was located in the COM standards that dealt with the necessity of redundant and diverse telecommunications, which was problematic for some in the industry based on a lack of common understanding as to what redundant and diverse actually entailed. This concept of redundant and diverse telecommunications was removed from the COM standards, and to bring the same phrase back in another standard, is likely to only continue the confusion without a common understanding throughout the industry as to what this would mean. Lastly, we assume that the data that this would pertain to is Real-time data, and we question whether an entire path (substation to primary control center) can ever be entirely redundant.

-Duke Energy requests that the drafting team take great care in clarifying/describing what will be expected of the industry regarding the monitoring on non-BES facilities as necessary. Placing this into a NERC standard without clearly putting defined parameters, and writing it so that entities will fully understand the instances in which certain facilities will need to be monitored especially with the great diversity of systems throughout the grid, will be challenging. Clearly defined parameters are necessary, in that it is not feasible to expect entities to monitor all non-BES facilities.

-Regarding the testing of less frequently used data capabilities, Duke Energy is concerned with the vagueness of the phrase “less frequently used”, and requests that the drafting team clearly define what should be considered “less frequently used capabilities”.

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Seattle City Light

Feb 18, 2016

SUBJECT: Project 2016-01 SAR Comments Modifications to TOP and IRO Standards

1. The SDT will be required to "*revise TOP-001-3 R10 (*FERC approved on 2015 Nov 19*) to require* TOPs *have real-time monitoring of non-BES facilities.*"

   Since City Light is already monitoring the non-BES facilities (or distribution systems) and with the new EMS system, City Light should meet these requirements without this having a big impact on City Light.

2. Per the requirement: "The SDT will be required to revise the newly approved TOP-001-3 R19 and R20 to require TOPs and BAs to *have the redundant and diversely routed data exchange capabilities."* In addition *"a data exchange capability testing framework for the data exchange capabilities to test the alternate or less frequently used data exchange capabilities* will be required."

   City Light is concerned that this might require us to install redundant hardware, software, and do performance testing. City Light would like clarity on the expectations.

3. This new NERC Standards Authorization Request project 2016-01 was proposed and submitted by NERC under the FERC directive (Order 817). The SDT will have to file a revised reliability standard addressing these issues for approval within 18 months of Order 817 effective date (Nov 19, 2015).

   SCL would like to work with the SDT to ensure they adopt clear and concise language during the standard development process such that implementation will be straight forward, clear and concise.

Sincerely,

Ginette Lacasse
Compliance Strategic Advisor
Seattle City Light

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Report

Project Name:	2016-01 Modifications to TOP and IRO Standards SAR
Comment Period Start Date:	1/22/2016
Comment Period End Date:	2/22/2016

There were 22 sets of responses representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed scope for Project 2016-01 as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

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

Summary Consideration. The SDT thanks all commenters. A summary of comments and the SDT's response is provided below:

- **Terms used in FERC Order 817 Directives. Some commenters recommended the scope of the project include explaining the meaning of *redundant and diverse routing* or other terms used in Order No. 817 related to this project; a commenter recommended developing a Standards Authorization Request to develop definition(s) for some terms.** The SDT believes the project scope as written in the SAR provides flexibility to draft clear requirements that are supported by appropriate Rationale and/or Guidelines and Technical Basis section guidance. If new or revised definitions are needed, the SDT believes this is also covered under the current SAR.
- **Defined term *Operating Instruction*. A commenter recommended reviewing use of the term in TOP-001-3 due to differences with the currently-enforceable standard (TOP-001-1a).** The SDT does not believe there is new information since industry approval of TOP-001-3 that warrants reviewing the use of the term *Operating Instruction* in Project 2016-01.
- **Concerns that the proposed standards will not benefit reliability. Some commenters argue that new requirements are not necessary to address the objectives outlined in the SAR because they believe the reliability issues are already covered (through existing requirements, BES definition, certification process, and/or other obligations and practices).** While some commenters believe the existing requirements support the directives in Order No. 817, some entities may not interpret existing requirements in a manner that would address the directives. The SDT notes that the directives were issued by FERC following considerable stakeholder commenting on the Notice of Proposed Rulemaking (NOPR) associated with Order No. 817. Arguments expressed by SAR commenters do not contain any new information that was not part of NOPR proceedings. Thus

the SDT believes the SAR scope is appropriate for addressing FERC's concerns through development of results-based requirement(s) that meet the directives.

- **<u>Reliability guideline as an alternate approach to meeting the reliability objectives.</u> A commenter recommended the SDT consider development of a reliability guideline as an equally efficient and effective method for meeting the directives.** The SDT does not believe a reliability guideline by itself provides obligations for entities to address the directives.
- **<u>Specific regional concerns.</u> An entity raised concerns with approved TOP-001-3 Requirement R10 due to challenges in the ERCOT region with TOP monitoring facilities outside its operating area.** The SDT does not believe there is new information since industry approval of TOP-001-3 and therefore does not support expanding the scope of Project 2016-01.
- **<u>Consider two projects.</u> A commenter observed that the subject matter of the directives may be suited for two separate projects.** The SDT considered the recommendation and believes the best way to address the directives is through a single project. This avoids overlapping efforts to revise standards concurrently.
- **<u>Suggestions for standards development.</u> Several commenters offered suggestions for the SDT to consider in developing the standards in this project.** The SDT reviewed all comments and will consider the recommendations.

Group Information

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Ben Engelby	6		ACES Standards Collaborators - TOP/IRO Project	Chip Koloini	ACES Power Marketing	3,5	SPP RE
					Bob Solomon	ACES Power Marketing	1	RF
					Shari Heino	ACES Power Marketing	1,5	Texas RE
					Mike Brytowski	ACES Power Marketing	1,3,5,6	MRO
					Ginger Mercier	ACES Power Marketing	1,3	SERC
					Ellen Watkins	ACES Power Marketing	1	SPP RE
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	MRO	3,4,5,6	MRO
					Chuck Lawrence	MRO	1	MRO
					Chuck Wicklund	MRO	1,3,5	MRO
					Dave Rudolph	MRO	1,3,5,6	MRO
					Kayleigh Wilkerson	MRO	1,3,5,6	MRO
					Jodi Jenson	MRO	1,6	MRO
					Larry Heckert	MRO	4	MRO

					Mahmood Safi	MRO	1,3,5,6	MRO
					Shannon Weaver	MRO	2	MRO
					Mike Brytowski	MRO	1,3,5,6	MRO
					Brad Perrett	MRO	1,5	MRO
					Scott Nickels	MRO	4	MRO
					Terry Harbour	MRO	1,3,5,6	MRO
					Tom Breene	MRO	3,4,5,6	MRO
					Tony Eddleman	MRO	1,3,5	MRO
					Amy Casucelli	MRO	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
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	New York Independent System Operator	2	NPCC
					Ben Li	New York Independent System Operator	2	NPCC
					Kathleen Goodman	New York Independent System Operator	2	NPCC
					Mark Holman	New York Independent System Operator	2	NPCC
					Charles Yeung	New York Independent System Operator	2	SPP RE
					Terry Bilke	New York Independent System Operator	2	MRO
					Nathan Bigbee	New York Independent	2	Texas RE

						System Operator		
					Ali Miremadi	New York Independent System Operator	2	WECC
Dominion - Dominion Resources, Inc.	Randi Heise	3,5,6		Dominion - RCS	Larry Nash	Dominion - Dominion Resources, Inc.	1	SERC
					Louis Slade	Dominion - Dominion Resources, Inc.	6	SERC
					Connie Lowe	Dominion - Dominion Resources, Inc.	3	RF
					Randi Heise	Dominion - Dominion Resources, Inc.	5	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no ISO-NE HQ and NextEra	Paul Malozewski	Northeast Power Coordinating Council	1	NPCC
					Guy Zito	Northeast Power	NA - Not Applicable	NPCC

						Coordinating Council		
					Brian Shanahan	Northeast Power Coordinating Council	1	NPCC
					Rob Vance	Northeast Power Coordinating Council	1	NPCC
					Mark J. Kenny	Northeast Power Coordinating Council	1	NPCC
					Gregory A. Campoli	Northeast Power Coordinating Council	2	NPCC
					Randy MacDonald	Northeast Power Coordinating Council	2	NPCC
					Wayne Sipperly	Northeast Power Coordinating Council	4	NPCC
					David Ramkalawan	Northeast Power	4	NPCC

						Coordinating Council		
					Glen Smith	Northeast Power Coordinating Council	4	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
					Brian Robinson	Northeast Power Coordinating Council	5	NPCC
					Bruce Metruck	Northeast Power Coordinating Council	6	NPCC
					Alan Adamson	Northeast Power Coordinating Council	7	NPCC
					Michael Jones	Northeast Power Coordinating Council	3	NPCC
					Michael Forte	Northeast Power	1	NPCC

						Coordinating Council		
					Kelly Silver	Northeast Power Coordinating Council	3	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
					Robert J Pellegrini	Northeast Power Coordinating Council	1	NPCC
					Edward Bedder	Northeast Power Coordinating Council	1	NPCC
					David Burke	Northeast Power Coordinating Council	3	NPCC
					Peter Yost	Northeast Power Coordinating Council	4	NPCC
					Helen Lainis	Northeast Power	2	NPCC

						Coordinating Council		
					Connie Lowe	Northeast Power Coordinating Council	4	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Jason Smith	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Jim Nail	Southwest Power Pool, Inc. (RTO)	3,5	SPP RE
					J. Scott Williams	Southwest Power Pool, Inc. (RTO)	1,4	SPP RE
					Kevin Giles	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP RE
					Ellen Watkins	Southwest Power Pool, Inc. (RTO)	1	SPP RE
					Sing Tay	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP RE

					John Allen	Southwest Power Pool, Inc. (RTO)	1,4	SPP RE
					Mike Kidwell	Southwest Power Pool, Inc. (RTO)	1,3,5	SPP RE
					Don Schmit	Southwest Power Pool, Inc. (RTO)	1,3,5	MRO

1. Do you agree with the proposed scope for Project 2016-01 as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.	
Thomas Foltz - AEP - 3,5	
Answer	No
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 believe a more prudent approach would be to focus on the desired end state itself. We believe the argument can be made that our existing obligations, when considered as a whole, could collectively appease FERC's concerns.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Comment	
We have no concern with the Commission's directive that there should be some additional language in reference to TOP-001-3 Requirement R10. Also, we agree that IRO-002-4 Requirement R3 can serve as a foundation for that particular language. We also suggest that the drafting team follow the Functional Model Advisory Group's efforts very closely so that any clarified functional obligations are captured and consistent with the Functional Model. Additionally, we would suggest the drafting team to clarify that the non-BES facilities that the TOP is required to monitor be only those facilities that were identified by the Reliability Coordinator in IRO-002-4. As for the Commission's suggestion of adding clarity to the term 'redundant infrastructure', our review group suggests the SDT consider developing a Standards Authorization Request (SAR) to create a definition for this particular term that can be added to the	

NERC Glossary, Rules of Procedure, and Functional Model. When the term "Alternative Interpersonal Communication" was created as a part of COM-001-2, the SDT included within the definition that the capability must use a different infrastructure. The definition of 'redundant infrastructure' could include the requirement to be diversely routed. We don't feel it is appropriate to have a blanket requirement for the TOP to be required to have fully redundant data exchange capabilities with each entity it has identified it needs data from. The Transmission Operator may only receive a handful of points from certain entities, and there may be minimal impact to reliability if that data was lost. Any new requirement or change to R19 and R20 should provide the Transmission Operator the ability to identify and declare the entities with which it needs to have fully redundant and diversely routed data exchange capability. In addition to the directives by FERC to modify the TOP and IRO standards, we suggest that the SDT review the use of the term 'Operating Instruction' as found in the TOP and IRO standards. It appears that the COM-002-4 Drafting Team did not intend to do a direct replacement of the term 'Directive' with 'Operating Instruction'. However, it appears the TOP-001-3 R3 and R4 are zero tolerance on compliance with EACH Operating Instruction. Previously the wording in the Standards required zero tolerance on the receipt of Directives. The definition of Operating Instruction is much broader and can be interpreted to include some system to system communications that were not previously considered to be Directives. We do not believe the intent of the term Operating Instruction in TOP-001-3 is consistent with the definition and use of the term in COM-002-4.	
Joshua Smith - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Comment	
The suggested revision of approved NERC Standard TOP-001-3, specifically Requirement 10, to require real-time monitoring of non-BES facilities is not needed and is already covered by the existing language. Requirement 10.1 states; "Within its Transmission Area, monitor facilities and the status of Special Protection Systems, and". R10.1 requires TOPs to monitor facilities to determine SOL exceedances, which allows the TOP to decide which "Facilities" it deems neccessary to meet the task required by R10. By adding the requirement to real-time monitor non-BES facilities, the Standard requires how something should be done instead of stating what is required and allowing the utility to decide how.	

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	No
Comment	
Florida Power and Light (FPL) appreciates the efforts of NERC drafting a SAR proposing changes to TOP-001-3 and IRO-002-4 to address concerns expressed during the FRCC Order No. 817. For the three specific concerns mentioned, Monitoring non-Bulk Electric Systems facilities, FPL believes the new TOP-001-3 standard and the BES definition addresses this concern and do not feel a standard revision is necessary. In the case of Redundancy and Diverse Routing of Data Exchange Capabilities, FPL believes the revised TOP and IRO standards adequately address redundancy and diverse routing of data exchange capabilities and do not feel additional standard revisions are necessary. Lastly, in the testing of the Alternative or Less Frequently Used Data Exchange Capability, FPL believes RCs, TOPs and BAs should have protocols to ensure their alternative data exchange capabilities are viable in order to comply with the revised TOP and IRO standards and in good utility practice; and do not feel additional standard requirements are necessary.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Comment	
ERCOT joins in the comments of the IRC Standards Review Committee (SRC). The SRC agrees that a drafting team needs to address the directives issued by FERC in Order No 817.	
William Temple - PJM Interconnection, L.L.C. - 2 - RF	
Answer	Yes
Comment	

PJM supports the comments submitted by the ISO/RTO Standards Review Committee (SRC).	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Comment	
: The SRC agrees that a drafting team needs to address the directives issued by FERC in Order No 817.	
Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - TOP/IRO Project	
Answer	Yes
Comment	
We agree that the scope of the SAR is drafted to address the FERC directives in Order No. 817. We ask the SDT to strongly consider cost implications and to explore equally efficient and effective alternatives to developing additional requirements. Such alternatives could include glossary term revisions, identifying existing standards that already address the directive, or the development of a reliability guideline.	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Comment	
The SDT directive to "revise TOP-001-3 R10 to require real-time monitoring of non-BES facilities" needs to be developed using clear criteria delineating when monitoring is required and what approach or parameters would constitute adequate monitoring.	

Jared Shakespeare - Peak Reliability - 1	
Answer	Yes
Comment	
Mark Kenny - Eversource Energy - 1,3	
Answer	Yes
Comment	
Si Truc Phan - Hydro-Quebec TransEnergie - 1 - NPCC	
Answer	Yes
Comment	
Nicolas Turcotte - Hydro-Quebec TransEnergie - 1	
Answer	Yes
Comment	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Comment	

Randi Heise - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion - RCS	
Answer	Yes
Comment	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Comment	
Jamison Dye - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Comment	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Comment	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Comment	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Comment	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE HQ and NextEra	
Answer	Yes
Comment	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy
Comment
Duke Energy has several thoughts regarding this project we would like to relay to the drafting team.

-Regarding redundancy and diverse routing of data exchange capabilities, Duke Energy requests that the drafting team clearly define what is meant by “data exchange capabilities”. This terminology seems rather vague at this point, and could use an adequate definition to clear up any possible ambiguity. Also, previously a requirement was located in the COM standards that dealt with the necessity of redundant and diverse telecommunications, which was problematic for some in the industry based on a lack of common understanding as to what redundant and diverse actually entailed. This concept of redundant and diverse telecommunications was removed from the COM standards, and to bring the same phrase back in another standard, is likely to only continue the confusion without a common understanding throughout the industry as to what this would mean. Lastly, we assume that the data that this would pertain to is Real-time data, and we question whether an entire path (substation to primary control center) can ever be entirely redundant.

-Duke Energy requests that the drafting team take great care in clarifying/describing what will be expected of the industry regarding the monitoring on non-BES facilities as necessary. Placing this into a NERC standard without clearly putting defined parameters, and writing it so that entities will fully understand the instances in which certain facilities will need to be monitored especially with the great diversity of systems throughout the grid, will be challenging. Clearly defined parameters are necessary, in that it is not feasible to expect entities to monitor all non-BES facilities.

-Regarding the testing of less frequently used data capabilities, Duke Energy is concerned with the vagueness of the phrase “less frequently used”, and requests that the drafting team clearly define what should be considered “less frequently used capabilities”.

2. Provide any additional comments for the SDT to consider, if desired.
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE HQ and NextEra
Comment

The SAR should allow the SDT to explain the meaning of "diverse routing" and "redundancy". A glossary term may not be needed but an explanation of the intent will be required to facilitate compliance. Also, as a general comment, FERC wanted to limit "redundancy and diversity" to data exchange between RC, TOP and BA so the SDT will need to avoid capturing other entities like TO and DP into this requirement.
Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - TOP/IRO Project
Comment
1. We recommend that the SDT conduct a technical conference relating to this project to explore any equally efficient and effective alternatives in lieu of modifying the existing standards. This would allow industry an opportunity to provide initial feedback prior to any proposed standard revisions. We also recommend that if the SDT agrees with this approach, that it considers broadcasting the technical conference via a webinar for industry stakeholders who are unable to attend in person. A recent technical conference held for NERC Project 2007-06.2 was limited to 20 people and was not open to a large majority of industry to attend. 2. For TOP-001-3 R10, we have concerns with the proposal of expanding the TOP's responsibilities for monitoring non-BES facilities. The SDT could consider alternatives including references to the existing BES exception process or the development of a reliability guideline. In the event that the SDT decides to pursue development of the requirement instead of identifying an alternative, we recommend limiting the scope of monitoring non-BES facilities to only the facilities that were identified by the Reliability Coordinator in IRO-002-4 and agreed to by the Transmission Operator. 3. For TOP-001-3 R19 and R20 relating to "redundant infrastructure," the SDT should consider developing a formal glossary term to provide clarity for the requirements. Cost considerations should also be factored into the development of these requirements. 4. Thank you for the opportunity to comment.
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee
Comment

The SRC would like NERC and the drafting team to consider alternatives to a reliability standard to address the directives included in the Order. The types of activities contemplated in the SAR are upstream and act as controls around registered entities performing core reliability functions, such as responding to IROL's or developing emergency plans. Redundant and diversely routed data exchange capabilities, in addition to testing of alternate or less frequently used data exchange capabilities are not core reliability requirements. Moreover, given the relatively static nature of these types of activities (e.g., establishing communications equipment), RC/BA/TOP Certification is a more appropriate program for the ERO to use to support reliable operations than auditing.

Also, the SRC would like the drafting team to consider clarifying "redundant and diversely routed data exchange capabilities". The SRC asks the SDT to consider whether data that goes to two independent control sites satisfy the concepts of redundant and diversely routed or does the SDT intend to require two independent feeds to each cite?

The SRC would also like the SDT to consider the applicability of non-BES Elements to the standards process. NERC is close to implementing an improved BES Definition on July 1, 2016, that will provide greater clarity to facilities that will impact the interconnected transmission system. The SDT should consider how this definition can capture elements that may not meet the core BES definition but should be BES going forward.

Joshua Smith - Oncor Electric Delivery - 1 - Texas RE

Comment

TOP-001-3 R10 as proposed requires each TOP shall monitor Facilities and the status of SPSs within its TOP area and obtain and utilize status, voltages and flow data for facilities and status of SPS outside its TOP area. The ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001-3 does it require TOs to supply neighboring TOs with this data. Oncor requests R10 be reworded to provide flexibility for region structure.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Comment

ERCOT joins in the comments of the IRC Standards Review Committee (SRC).

The SRC would like NERC and the drafting team to consider alternatives to a reliability standard to address the directives included in the Order. The types of activities contemplated in the SAR are upstream and act as controls around registered entities performing core reliability functions, such as responding to IROL's or developing emergency plans. Redundant and diversely routed data exchange capabilities, in addition to testing of alternate or less frequently used data exchange capabilities are not core reliability requirements. Moreover, given the relatively static nature of these types of activities (e.g., establishing communications equipment), RC/BA/TOP Certification is a more appropriate program for the ERO to use to support reliable operations than auditing.

Also, the SRC would like the drafting team to consider clarifying "redundant and diversely routed data exchange capabilities". The SRC asks the SDT to consider whether data that goes to two independent control sites satisfy the concepts of redundant and diversely routed or does the SDT intend to require two independent feeds for each data sample to each site?

The SRC would also like the SDT to consider the applicability of non-BES Elements to the standards process. NERC is close to implementing an improved BES Definition on July 1, 2016, that will provide greater clarity to facilities that will impact the interconnected transmission system. The SDT should consider how this definition can capture elements that may not meet the core BES definition but should be BES going forward.

Thomas Foltz - AEP - 3,5

Comment

Though the directives given by FERC potentially impact the same standard(s), and the"identification of non-BES elements" and "redundant data exchange capabilities"emanate from the same FERC Order, the topics appear disparate enough to drive two separate projects. Would it be preferable to create two separate project teams to pursue the FERC directives, rather than combine multiple, dissimilar directives into a single project?

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body
Comment
1. The SDT will be required to "revise TOP-001-3 R10 (FERC approved on 2015 Nov 19) to require TOPs have real-time monitoring of non-BES facilities." Since City Light is already monitoring the non-BES facilities (or distribution systems) and with the new EMS system, City Light should meet these requirements without this having a big impact on City Light. 2. Per the requirement: "The SDT will be required to revise the newly approved TOP-001-3 R19 and R20 to require TOPs and BAs to have the redundant and diversely routed data exchange capabilities." In addition "a data exchange capability testing framework for the data exchange capabilities to test the alternate or less frequently used data exchange capabilities will be required." City Light is concerned that this might require us to install redundant hardware, software, and do performance testing. City Light would like clarity on the expectations. 3. This new NERC Standards Authorization Request project 2016-01 was proposed and submitted by NERC under the FERC directive (Order 817). The SDT will have to file a revised reliability standard addressing these issues for approval within 18 months of Order 817 effective date (Nov 19, 2015). SCL would like to work with the SDT to ensure they adopt clear and concise language during the standard development process such that implementation will be straight forward, clear and concise.
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)
Comment
Per section 47 of FERC Order 817, recommend adding Reliability Standards IRO-002-4, Requirement R4 to clarify what "redundant infrastructure" is, within this SAR.

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016

Anticipated Actions	Date
45-day formal comment period with ballot	June 2016
45-day formal comment period with additional ballot	September 2016
10-day final ballot	November 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-5
3. **Purpose:** To provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirements R1 and R2: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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 Reliability Coordinator's Control Center. 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 Control Center.

Infrastructure that is not within the RC's Control Center is not addressed by the proposed requirement.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

Rationale for Requirement R3: The revised requirement addresses directives for testing of data exchange capabilities (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R3. Each Reliability Coordinator shall test its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its data exchange capabilities specified in Requirement R2 for redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and provide upon request evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

R5. Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R4 and Measures M1, M2, and M4.
- The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 and Measures M5 and M6 for the current calendar year and one previous calendar year.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2.	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, as specified in the requirement.	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.
R3.	The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant	The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant	The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant	The Reliability Coordinator did not test its data exchange capabilities specified in Requirement R2 for redundant

	functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	functionality at least once each calendar month; OR The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month but, following an unsuccessful test, did not initiate action to restore the redundant functionality in more than 8 hours.
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
R5.	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability

				Operating Limit exceedances within its Reliability Coordinator Area.
R6.	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:

The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:

Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for R6:

Requirement R6 was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-~~4~~5
3. **Purpose:** To ~~Provide~~ provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability**

   4.1. Functional Entities

   ~~4.1.~~4.1.1 Reliability Coordinator
5. **Effective Date:**

   See Implementation Plan~~.~~

~~6. Background:~~

~~See the Project 2014~~2016~~-03~~ ~~01~~.

B. Requirements and Measures

Rationale for Requirements R1 and R2: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47). 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 Reliability Coordinator's (RC) Control Center. 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 Control Center. Infrastructure that is not within the RC's Control Center is not addressed by the proposed requirement.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments~~. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its ~~operational~~ Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments~~.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

Rationale for Requirement R3: The revised requirement addresses directives for testing of data exchange capabilities (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R3. Each Reliability Coordinator shall test its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its data exchange capabilities specified in Requirement R2 for redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

~~R2.~~R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

~~M1.~~M4. Each Reliability Coordinator shall, have and provide upon request evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

~~R3.~~R5. Each Reliability Coordinator shall monitor Facilities, the status of ~~Special Protection System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any ~~-~~System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of ~~Special Protection System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

~~R4.~~R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~1.2. Compliance Monitoring and Assessment Processes:~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~1.2. ~~Data~~ Evidence Retention

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

~~The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and ~~R3~~R4 and Measures M1, M2, and ~~M3~~M4.

The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 ~~R4~~ and Measures M5 and M6 ~~M4~~ for the current calendar year and one previous calendar year.

~~If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.~~

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~1.4. Additional Compliance Information~~

~~None.~~

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, as specified in the requirement.	
R3	The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Reliability Coordinator did not test its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month; OR The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month but, following an unsuccessful test, did not initiate action to restore the redundant functionality in more than 8 hours.
~~R2~~R4	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
~~R3~~R5	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of ~~Special Protection System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
~~R4~~R6	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The Implementation Plan and other project documents can be found on the project page.~~None.~~

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
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2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised

3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

~~**Rationale:**~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:
The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The ~~SDT~~Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:
Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for ~~R4~~R6:

Requirement ~~R4~~ R6 was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016

Anticipated Actions	Date
45-day formal comment period with ballot	June 2016
45-day formal comment period with additional ballot	September 2016
10-day final ballot	November 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Transmission Operations**
2. **Number:** TOP-001-4
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.2. Transmission Operator

   4.1.3. Generator Operator

   4.1.4. Distribution Provider

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the

Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings,

electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining SOL exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4, which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability are monitored. These facilities should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

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

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

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

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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.

Infrastructure that is not within the TOP's Control Center is not addressed by the proposed requirement.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange 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]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities, with redundant and diversely routed data exchange 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 to perform it Real-time monitoring and Real-time Assessments as specified in the requirement.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R21. Each Transmission Operator shall test its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have and provide upon request, evidence that it tested its data exchange capabilities specified in Requirement R20 for redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Rationale for Requirements R22 and R23: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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 Balancing Authority's (BA) Control Center. Requirement R23 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 BA Control Center.

Infrastructure that is not within the BA's Control Center is not addressed by the proposed requirement.

R22. Each Balancing Authority shall have data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M22. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, 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 analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, 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 to perform it Real-time monitoring and analysis functions as specified in the requirement.

Rationale for Requirement R24: The proposed requirement addresses directives for testing of data exchange capabilities (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R24. Each Balancing Authority shall test its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have and provide upon request, evidence that it tested its data exchange capabilities specified in Requirement R23 for redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL Tv as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.

- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R20, and Measure M15 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall each keep data or evidence for each applicable Requirement R22 through R23, and Measure M22 through M23 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Instruction issued by its Transmission Operator.
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				safety, equipment, regulatory, or statutory requirements.
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities,	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	channels between the affected entities.	channels between the affected entities.		telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items listed in Requirement R10 Part 10.1 through 10.6.
R11	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	The Transmission Operator did not	The Transmission Operator did not have	The Transmission Operator did not have	The Transmission Operator did not have data exchange

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's Control Center, as specified in the Requirement.	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R21	The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Transmission Operator did not test its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month; OR The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.
R22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		applicable entities, whichever is greater.	entities, whichever is greater.	
R23	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, as specified in the Requirement.	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.
R24	The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to	The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to	The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant	The Balancing Authority did not test its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month; OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	functionality in more than 6 hours and less than or equal to 8 hours.	The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is:
http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	
4	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20:

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

A. Introduction

1. **Title: Transmission Operations**

2. **Number: TOP-001-~~3~~4**

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

5. **Effective Date:**

   See Implementation Plan~~.~~

~~6. Background:~~

~~See Project 2014-03 project page.~~

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and

provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings,

electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining SOL exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4, which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability are monitored. These facilities should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

R10. Each Transmission Operator shall perform the following ~~as necessary~~ for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. ~~Within its Transmission Operator Area, monitor~~ Monitor Facilities within its Transmission Operator Area; ~~and~~

10.2. Monitor the status of ~~Special Protection Systems~~Remedial Action Schemes within its Transmission Operator Area;

~~10.1.~~10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;~~and~~

10.4. ~~Outside its Transmission Operator Area, o~~Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

~~**10.2.** and the status of Special Protection Systems.~~

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

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_V. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

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

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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.

Infrastructure that is not within the TOP's Control Center is not addressed by the proposed requirement.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning

Analyses.~~the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.~~ *[Violation Risk Factor: ~~High~~Medium]* *[Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Transmission Operator Area~~perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange 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]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities, with redundant and diversely routed data exchange 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 to perform it Real-time monitoring and Real-time Assessments as specified in the requirement.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R21. Each Transmission Operator shall test its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its data exchange capabilities specified in Requirement R20 for redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Rationale for Requirements R22 and R23: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47). 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 Balancing Authority's (BA) Control Center. Requirement R23 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 BA Control Center. Infrastructure that is not within the BA's Control Center is not addressed by the proposed requirement.

~~R20.~~R22. Each Balancing Authority shall have data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to develop its Operating Plan for next-day operations.~~maintain reliability in its Balancing Authority Area.~~ *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M2~~0~~2. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Balancing Authority Area~~develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, 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 analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, 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 to perform it Real-time monitoring and analysis functions as specified in the requirement.

> **Rationale for Requirement R24:** The proposed requirement addresses directives for testing of data exchange capabilities (FERC Order No. 817 Para 51).
>
> A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R24. Each Balancing Authority shall test its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its data exchange capabilities specified in Requirement R23 for redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~As defined in the NERC Rules of Procedure,~~ "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable ~~the NERC~~ Reliability Standards in their respective jurisdictions.

~~**1.2. Compliance Monitoring and Assessment Processes**~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be~~

~~used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~1.2. ~~Data~~ Evidence Retention

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full time period since the last audit.~~

Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and ~~R15 through R20 and~~ Measure M1 through M11~~, and M15 through M20~~ for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ~~ninety~~ 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.

~~and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.~~

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

Each Transmission Operator shall retain evidence ~~and~~ that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.

Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R20, and Measure M15 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Balancing Authority shall each keep data or evidence for each applicable Requirement R22 through R23, and Measure M22 through M23 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

~~If a Balancing Authority, Transmission Operator, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.~~

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~**1.4. Additional Compliance Information**~~

~~None.~~

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities,	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Emergency on respective Balancing Authority Areas.	resulted in, an Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items listed in Requirement R10, Part 10.1 through 10.6.~~N/A~~	The Transmission Operator did not monitor, obtain, or utilize two of the items listed in Requirement R10, Part 10.1~~.~~ through 10.6. ~~OR,~~ ~~The Transmission Operator did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.~~	The Transmission Operator did not monitor, obtain, or utilize three of the items listed in Requirement R10, Part 10.1 through 10.6 ~~and did not obtain and utilize one of the items listed in Requirement R10, Part 10.2~~.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items listed in Requirement R10 Part 10.1 through 10.6.~~Facilities and the status of Special Protection Systems within its Transmission Operator Area and did not obtain and utilize data deemed as necessary from outside its Transmission Operator Area.~~
R11	N/A	N/A	The Balancing Authority did not monitor the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			within its Balancing Authority Area and support Interconnection frequency.	
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				instances where there was a difference in SOLs.
R19	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's Control	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Center, as specified in the Requirement.	
R21	The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Transmission Operator did not test its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month; OR The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.
~~R20~~R22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity,	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	or 5% or less of the applicable entities, whichever is greater.	entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	less than or equal to 15% of the applicable entities, whichever is greater.	applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, as specified in the Requirement.	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.
R24	The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar	The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar	The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month but, following an	The Balancing Authority did not test its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month;

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The ~~SDT~~Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	
4	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

~~**Rationale:**~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20:

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

Implementation Plan

Project 2016-01 Modifications to TOP and IRO Standards
Reliability Standards IRO-002-5 and TOP-001-4

Applicable Standard(s)

- IRO-002-5 - Reliability Coordination - Monitoring and Analysis
- TOP-001-4 - Transmission Operations

Requested Retirement(s)

- IRO-002-4 - Reliability Coordination - Monitoring and Analysis
- TOP-001-3 - Transmission Operations

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

On November 19, 2015, the Federal Energy Regulatory Commission (FERC) issued Order No. 817 approving nine revised or new TOP and IRO Reliability Standards from Project 2014-03 that addressed previously-identified reliability issues and concerns. In approving the standards, FERC also directed development of modifications to TOP and IRO standards to address specific concerns related to: (i) Transmission Operator monitoring of some non-Bulk Electric System (non-BES) elements needed for reliable operations, and (ii) redundancy in data exchange capabilities used by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable operations.

General Considerations

The three-month implementation period for IRO-002-5 provides Reliability Coordinators with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality. The proposed implementation plan presumes that IRO-002-4 is effective, or will become effective, on or before the effective date of IRO-002-5.

The 12-month implementation period for TOP-001-3 provides Transmission Operators (TOP) with time to revise and distribute data specifications required by TOP-003-3 Requirement R1 to include non-BES data identified by the TOP, and receive data from entities responsible for providing the data as required by TOP-003-3 Requirement R5. The implementation period also provides TOPs and Balancing Authorities (BAs) with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality.

Effective Date

IRO-002-5
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-001-4
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

IRO-002-4
Reliability Standard IRO-002-4 shall be retired immediately prior to the effective date of IRO-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

TOP-001-3
Reliability Standard TOP-001-3 shall be retired immediately prior to the effective date of TOP-001-4 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2016-01 Modifications to TOP and IRO Standards

Do not use this form for submitting comments. Use the electronic form to submit comments on **IRO-002-5 – Reliability Coordination - Monitoring and Analysis** and **TOP-001-4 – Transmission Operations**. The electronic form must be submitted by **8 p.m. Eastern, Wednesday, August 3, 2016.**

Additional information about this project is available on the Project 2016-01 Modifications to TOP and IRO Standards project page. If you have questions, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

Background Information

On November 19, 2015, the Federal Energy Regulatory Commission (FERC) issued Order No. 817 approving revised TOP and IRO standards and directing modifications to address the following reliability concerns:

- Transmission Operator (TOP) monitoring of non-Bulk Electric System (BES) facilities as necessary for reliability (P. 35);
- Redundancy and diverse routing of data exchange capabilities used by Reliability Coordinators (RC), Balancing Authorities (BA), and TOPs (P. 47); and
- Testing of alternate data exchange capabilities used in RC, TOP, and BA control centers (P. 51).

FERC established a deadline of July 2017 for NERC to file modifications to standards addressing the above directives.

Proposed IRO-002-5 and TOP-001-4 contain revised and new requirements addressing the Order No. 817 directives. The Standards Drafting Team (SDT) provided justification for each requirement in the accompanying rationale boxes. Additionally, the SDT replaced the defined term *Special Protection System (SPS)* in the approved standards with the approved defined term *Remedial Action Scheme (RAS).* The SDT did not make any other changes to the requirements in the approved standards.

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.

   ☐ Yes
   ☐ No

   Comments:

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.

   ☐ Yes
   ☐ No

   Comments:

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.

   ☐ Yes
   ☐ No

   Comments:

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.

   ☐ Yes
   ☐ No

   Comments:

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.

☐ Yes
☐ No

Comments:

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

Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-01 - Modifications to TOP and IRO Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Reliability Standard requirements developed in Project 2016-01. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. 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.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance
Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties
A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement
VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

Project 2016-01 Reliability Standards Requirements

The SDT developed new or revised requirements in IRO-002-5 and TOP-001-4 to address reliability objectives outlined in the project Standard Authorization Request (SAR). The VRF and VSL justification for these new and revised requirements is described below. VRF and VSL justification for requirements that were not modified in Project 2016-01 can be found on the Project 2014-03 Project Page.

VRF Justification

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	High
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirement is not directly connected to an area identified in the Blackout Report.

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The proposed VRF is unchanged from approved TOP-001-3 Requirement R10. Additionally, the requirement is similar to approved IRO-002-4 Requirement R3 which applies to Reliability Coordinators and is assigned a High VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement addresses a single reliability objective and has a single VRF.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Operations Planning time horizon, which are not the subject of the Blackout Report recommendations regarding data exchange. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements address data exchange capabilities for the Operations Planning time horizon only, which is a significant change from approved IRO-002-4 Requirement R1 and TOP-001-3 Requirements R19 and R20 which apply to all operations time horizons. As proposed, the VRF will establish consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a Medium VRF. Failure to have data exchange capabilities necessary for performing Operational Planning Analysis or for developing an Operating Plan for next day operations could directly and adversely affect the electrical state or capability of the BES, or the ability to effectively control or restore the BES. However, this failure is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Same-day Operations and Real-time Operations time horizons. A High VSL is assigned to reflect the potential impact on the reliability of the BES consistent with the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements improve upon requirements for data exchange capabilities in approved IRO-002-4 and TOP-001-3, which are assigned a High VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a High VRF. Failure to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Control Center, for performing Real-time monitoring and analysis could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements are not directly connected to an area identified in the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	These are new requirements. Approved COM-001-2.1 Requirement R9 requires periodic testing of Alternate Interpersonal Communications capability and is assigned a Medium VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5, proposed TOP-001-4, and approved COM-001-2.1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for Medium VRF. Failure to periodically test data exchange capabilities for redundant functionality could, under anticipated data exchange infrastructure failure, affect the ability to monitor and control the BES. However, failure to test data exchange capabilities for redundant functionality is not likely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VSL Justification

VSLs for TOP-001-4 Requirement R10			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not monitor, obtain, or utilize one of the items listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items listed in Requirement R10 Part 10.1 through 10.6.

VSL Justifications for TOP-001-4 Requirement R10	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved TOP-001-3 Requirement R10.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for TOP-001-4 Requirement R10	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22			
Lower	**Moderate**	**High**	**Severe**
The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with one identified entity, or 5% or less of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with two identified entities, or more than 5% or less than or equal to 10% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with three identified entities, or more than 10% or less than or equal to 15% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with four or more identified entities or greater than 15% of the identified entities, whichever is greater.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved IRO-002-4 Requirement R1 and approved TOP-001-3 Requirements R19 and R20.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The applicable entity had data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), but did not have redundant and diversely routed data exchange infrastructure	The applicable entity did not have data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), as specified in the Requirement.

		within its Control Center, as specified in the Requirement.	

VSL Justifications for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24			
Lower	**Moderate**	**High**	**Severe**
The applicable entity tested its data exchange capabilities for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The applicable entity tested its data exchange capabilities for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The applicable entity tested its data exchange capabilities for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The applicable entity did not test its data exchange capabilities for redundant functionality at least once each calendar month; OR The applicable entity tested its data exchange capabilities for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

Order No. 817 Citation	Directive / Guidance	Resolution
P 35	Revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities.	The directive is addressed in proposed TOP-001-4 Requirement R10. Parts 10.3 and 10.6 cover non-BES facilities. ***Proposed TOP-001-4*** **R10.** Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.1.** Monitor Facilities within its Transmission Operator Area; **10.2.** Monitor the status of Remedial Action Schemes within its Transmission Operator Area; **10.3.** Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator; **10.4.** Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator; **10.5.** Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and **10.6.** Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

Order No. 817 Citation	Directive / Guidance	Resolution
P 47	Modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing. In addition, [the Commission directs] NERC to clarify that “redundant infrastructure” for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.	Proposed TOP-001-4 Requirements R20 and R23 address the directive for Transmission Operators (TOP) and Balancing Authorities (BA), respectively. For consistency, the Standards Drafting Team (SDT) developed proposed IRO-002-5 Requirement R2 to address the directive for Reliability Coordinators (RCs) rather than develop a modification to IRO-002-4 Requirement R4. ***Proposed TOP-001-4*** **R20.** Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange 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. **R23.** Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, 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 analysis functions. ***Proposed IRO-002-5*** **R2.** Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and

Order No. 817 Citation	Directive / Guidance	Resolution
		with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments.
P 51	Develop a modification to the TOP and IRO standards that 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.	The directive is addressed in proposed TOP-001-4 Requirements R21 and R24, and proposed IRO-002-5 Requirement R3. ***Proposed TOP-001-3*** **R21.** Each Transmission Operator shall test its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. **R24.** Each Balancing Authority shall test its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. ***Proposed IRO-002-5*** **R3.** Each Reliability Coordinator shall test its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality.

Standards Announcement
Reminder
Project 2016-01 Modifications to TOP and IRO Standards
IRO-002-5 and TOP-001-4

Initial Ballots and Non-binding Polls Open through August 3, 2016

Now Available

Initial ballots for **IRO-002-5 – Reliability Coordination - Monitoring and Analysis** and **TOP-001-4 – Transmission Operations** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Wednesday, August 3, 2016**.

Balloting
Members of the ballot pools associated with this project may log in and submit their votes for the standards and non-binding polls here. If you experience any difficulties in using the electronic form, contact Wendy Muller.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

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Standards Announcement

Project 2016-01 Modifications to TOP and IRO Standards
IRO-002-5 and TOP-001-4

Formal Comment Period Open through August 3, 2016

Now Available

A 45-day formal comment period for **IRO-002-5 – Reliability Coordination - Monitoring and Analysis** and **TOP-001-4 – Transmission Operations** is open through **8 p.m. Eastern, Wednesday, August 3, 2016**.

Commenting

Use the electronic form to submit comments on the standards. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Tuesday, July 19, 2016.** Registered Ballot Body members may join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

Initial ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 25 – August 3, 2016**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/53)
Ballot Name: 2016-01 Modifications to TOP and IRO Standards IRO-002-5 IN 1 ST
Voting Start Date: 7/25/2016 12:01:00 AM
Voting End Date: 8/3/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 229
Total Ballot Pool: 271
Quorum: 84.5
Weighted Segment Value: 67.25

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	65	1	31	0.674	15	0.326	0	11	8
Segment: 2	9	0.5	4	0.4	1	0.1	0	2	2
Segment: 3	59	1	29	0.707	12	0.293	0	10	8
Segment: 4	17	1	7	0.7	3	0.3	0	2	5
Segment: 5	62	1	25	0.641	14	0.359	0	12	11
Segment: 6	45	1	16	0.516	15	0.484	0	8	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	2	0.1	0	0	1	0.1	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.7	5	0.5	2	0.2	0	1	1
Totals:	271	6.6	120	4.438	63	2.162	0	46	42

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	Platte River Power Authority	Matt Thompson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	None	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Salt River Project	Rudy Navarro		None	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Comments Submitted
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Third-Party Comments
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Negative	Comments Submitted
5	Westar Energy	stephanie johnson		Abstain	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Negative	Comments Submitted
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		Negative	Comments Submitted
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	David Greene		Abstain	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

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Showing 1 to 271 of 271 entries

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/53)
Ballot Name: 2016-01 Modifications to TOP and IRO Standards TOP-001-4 IN 1 ST
Voting Start Date: 7/25/2016 12:01:00 AM
Voting End Date: 8/3/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 260
Total Ballot Pool: 303
Quorum: 85.81
Weighted Segment Value: 64.59

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	39	0.629	23	0.371	0	6	7
Segment: 2	9	0.5	4	0.4	1	0.1	0	2	2
Segment: 3	66	1	33	0.66	17	0.34	0	5	11
Segment: 4	19	1	9	0.643	5	0.357	0	0	5
Segment: 5	71	1	34	0.63	20	0.37	0	6	11
Segment: 6	49	1	22	0.537	19	0.463	0	3	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	2	0.1	0	0	1	0.1	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.6	4	0.4	2	0.2	0	2	1
Totals:	303	6.5	148	4.198	88	2.302	0	24	43

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Stanley Beasley	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Johnny Anderson		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	Platte River Power Authority	Matt Thompson		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	None	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth	Todd Komaromy	Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Austin Energy	Julie Ross		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Negative	Comments Submitted
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		None	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Fred Frederick		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Comments Submitted
3	Westar Energy	Bo Jones		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		None	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	Acciona Energy North America	George Brown		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Negative	Comments Submitted
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Platte River Power Authority	Tyson Archie		Negative	Comments Submitted
5	Portland General Electric Co.	Barbara Croas		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	SunPower	Bradley Collard		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Negative	Comments Submitted
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Negative	Comments Submitted
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
6	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Talen Energy Marketing, LLC	Elizabeth Davis		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		Negative	Comments Submitted
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
10	SERC Reliability Corporation	David Greene		Abstain	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

Showing 1 to 303 of 303 entries

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/53)
Ballot Name: 2016-01 Modifications to TOP and IRO Standards IRO-002-5 Non-binding Poll IN 1 NB
Voting Start Date: 7/25/2016 12:01:00 AM
Voting End Date: 8/3/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 216
Total Ballot Pool: 257
Quorum: 84.05
Weighted Segment Value: 64.05

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	61	1	23	0.639	13	0.361	0	19	6
Segment: 2	8	0.4	3	0.3	1	0.1	0	3	1
Segment: 3	59	1	24	0.686	11	0.314	0	14	10
Segment: 4	15	0.9	6	0.6	3	0.3	0	2	4
Segment: 5	59	1	22	0.667	11	0.333	0	14	12
Segment: 6	41	1	12	0.462	14	0.538	0	9	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	2	0.1	0	0	1	0.1	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.6	5	0.5	1	0.1	0	2	1
Totals:	257	6.3	98	4.153	55	2.147	0	63	41

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Michael DeLoach		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		None	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Comments Submitted
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Georgia System Operations Corporation	Guy Andrews		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City of Independence, Power and Light Department	Jim Nail		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Portland General Electric Co.	Barbara Croas		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	Westar Energy	stephanie johnson		Abstain	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Negative	Comments Submitted
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Abstain	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

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Showing 1 to 257 of 257 entries

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/53)
Ballot Name: 2016-01 Modifications to TOP and IRO Standards TOP-001-4 Non-binding Poll IN 1 NB
Voting Start Date: 7/25/2016 12:01:00 AM
Voting End Date: 8/3/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 234
Total Ballot Pool: 278
Quorum: 84.17
Weighted Segment Value: 65.43

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	68	1	31	0.674	15	0.326	0	15	7
Segment: 2	8	0.4	3	0.3	1	0.1	0	3	1
Segment: 3	64	1	28	0.651	15	0.349	0	9	12
Segment: 4	16	1	8	0.727	3	0.273	0	1	4
Segment: 5	65	1	28	0.683	13	0.317	0	11	13
Segment: 6	43	1	17	0.515	16	0.485	0	5	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	2	0.1	0	0	1	0.1	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.6	5	0.5	1	0.1	0	2	1
Totals:	278	6.4	123	4.35	65	2.05	0	46	44

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	Eversource Energy	Quintin Lee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Stanley Beasley	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	Negative	Comments Submitted
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Michael DeLoach		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth	Todd Komaromy	Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		None	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Comments Submitted
3	Westar Energy	Bo Jones		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		None	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	Acciona Energy North America	George Brown		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Negative	Comments Submitted
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Portland General Electric Co.	Barbara Croas		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	SunPower	Bradley Collard		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Negative	Comments Submitted
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Abstain	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

Showing 1 to 278 of 278 entries

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2016-01 Modifications to TOP and IRO Standards
IRO-002-5 and TOP-001-4

Formal Comment Period Open through August 3, 2016

Now Available

A 45-day formal comment period for **IRO-002-5 – Reliability Coordination - Monitoring and Analysis** and **TOP-001-4 – Transmission Operations** is open through **8 p.m. Eastern, Wednesday, August 3, 2016**.

Commenting
Use the electronic form to submit comments on the standards. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Tuesday, July 19, 2016.** Registered Ballot Body members may join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps
Initial ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 25 – August 3, 2016**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

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 IRO-002-5 Non-binding Poll IN 1 NB 2016-01 Modifications to TOP and IRO Standards TOP-001-4 IN 1 ST 2016-01 Modifications to TOP and IRO Standards TOP-001-4 Non-binding Poll IN 1 NB

There were 63 sets of responses, including comments from approximately 58 different people from approximately 55 companies representing 10 of the Industry Segments as shown in the table on the following pages.

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.

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
					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
					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
					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
					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
					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

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 and Energy Marketing	6	SERC
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

					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
					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

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
					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.

Thomas Foltz - 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	

Response

Justin Wilderness - 1

Answer	No
Document Name	

Comment

What defines the list of facilities that are required to be telemetered and used ?

Likes 0	
Dislikes 0	

Response

Jim Nail - 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	

Response

Brad Lisembee - 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	

Response

Anthony Jablonski - 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	

Response	
Paul Mehlhaff - 1	
Answer	No
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - 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	
Response	
Diana McMahon - 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	
Response	

Dennis Chastain - 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	
Response	

Rachel Coyne - 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	
Response	
David Bueche - 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	
Response	
Colleen Campbell - 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	

Response	
Terry Harbour - 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	
Response	
Sandra Shaffer - 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	
Response	
Jeffrey Watkins - 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	

Response

Laurie Williams - 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	

Response

Douglas Webb - 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	
Response	

Oliver Burke - 1

Answer	Yes
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	
Response	

Shawna Speer - 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	
Response	

Jaclyn Massey - 5

Answer	Yes
Document Name	
Comment	
no comments	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - 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	
Response	
Catrina Martin - 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	
Response	
Stephanie Burns - 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	
Response	
Stephanie Burns - 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	
Response	
sean erickson - 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	
Response	
Shannon Mickens - 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	
Response	
Jamie Monette - 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	
Response	
Shawn Abrams - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Likes 0	
Dislikes 0	
Response	
David Kiguel - 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randi Heise - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Langston - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Pamela Hunter - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Chris Gowder - 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	

Response

Quintin Lee - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ruida Shu - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Beilfuss - 1,3,4,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Chris Scanlon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Emily Rousseau - 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	
Response	

Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	
Document Name	
Comment	

No opinion	
Likes 0	
Dislikes 0	
Response	
Ben Li - 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	
Response	
Elizabeth Axson - 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	
Response	
Oshani Pathirane - 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	
Response	

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.	
Douglas Webb - 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	
Response	
Laurie Williams - 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	
Response	
Jeffrey Watkins - 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	
Response	
Terry Harbour - 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	
Response	

Shawn Abrams - 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	

Response

Colleen Campbell - 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	

Response

Matthew Beilfuss - 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	
Response	
David Bueche - 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	
Response	

Rachel Coyne - 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	

Response

Colby Bellville - 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	
Response	

Chris Gowder - 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	
Response	

Pamela Hunter - 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	
Response	

Tyson Archie - 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	

Response

Si Truc Phan - 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	

Response

Dennis Chastain - 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	

Response

Diana McMahon - 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	
Response	
Paul Mehlhaff - 1	
Answer	No
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	
Response	
Jaclyn Massey - 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	
Response	
Oliver Burke - 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	
Response	
Tom Hanzlik - 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	
Response	
John Williams - 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	
Response	
Justin Wilderness - 1	
Answer	No

Document Name	
Comment	

What is the definition of Redundant and Diversely routed data exchange ?

Likes 0	
Dislikes 0	
Response	

Jack Stamper - 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	
Response	

Sandra Shaffer - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Langston - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - 1	
Answer	No
Document Name	2016-01_TOP-001-4_Draft-1_Question-2.docx
Comment	
Likes 0	
Dislikes 0	
Response	
David Kiguel - 8	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - 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	
Response	
Shannon Mickens - 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	
Response	
sean erickson - 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	
Response	
Stephanie Burns - 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	
Response	
Stephanie Burns - 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	
Response	
Ruida Shu - 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	
Response	

Quintin Lee - 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	
Response	
Catrina Martin - 5	
Answer	Yes
Document Name	
Comment	
It would be nice if redundant and diversely routed where defined terms.	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - 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	
Response	

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

Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Vine - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawna Speer - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	

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

Anthony Jablonski - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Nail - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - 1	
Answer	
Document Name	
Comment	
We understand that these changes are to address a FERC Directive.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - 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	

Response
Gregory DAnnibale - NA - Not Applicable - NPCC

Answer	
Document Name	

Comment
No opinion

Likes 0	
Dislikes 0	

Response
Emily Rousseau - 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	

Response

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.

Jack Stamper - 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	
Response	
Thomas Foltz - 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	
Response	

Jim Nail - 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	
Response	
John Williams - 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	
Response	
Tom Hanzlik - 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	
Response	
Oliver Burke - 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	
Response	
Jaclyn Massey - 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	
Response	
Paul Mehlhaff - 1	
Answer	No
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - 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	
Response	
Dennis Chastain - 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	
Response	
Kelly Silver - 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	
Response	
Pamela Hunter - 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	
Response	
Quintin Lee - 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	
Response	
Ruida Shu - 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	
Response	
Colby Bellville - 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	
Response	
Elizabeth Axson - 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	
Response	
Rachel Coyne - 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	
Response	
David Bueche - 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	

Response

Colleen Campbell - 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	
Response	
Oshani Pathirane - 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	
Response	
Shawn Abrams - 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	

Response	
Terry Harbour - 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	
Response	
Chris Scanlon - 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	
Response	
Jeffrey Watkins - 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	

Response

Laurie Williams - 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	

Response

Douglas Webb - 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	

Response

Scott Langston - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Justin Wilderness - 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	
Response	
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	

Response

Joe Tarantino - 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	

Response

Andrew Pusztai - 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	
Response	
Catrina Martin - 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	
Response	
Stephanie Burns - 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	
Response	

Stephanie Burns - 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	
Response	

Shannon Mickens - 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	
Response	

ALAN ADAMSON - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brad Lisembee - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1;

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Randi Heise - 5, Group Name Dominion - RCS

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Shawna Speer - 1, Group Name Colorado Springs Utilities

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Richard Vine - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - 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	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - 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	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	
Document Name	
Comment	
No opinion	
Likes 0	
Dislikes 0	
Response	

Matthew Beilfuss - 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	
Response	
Jamie Monette - 1	
Answer	
Document Name	
Comment	
We understand that these changes are to address a FERC Directive.	
Likes 0	
Dislikes 0	
Response	

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.

Douglas Webb - 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	

Response

Laurie Williams - 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	

Response

Jeffrey Watkins - 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	
Response	
Sandra Shaffer - 6	
Answer	No
Document Name	
Comment	
"Necessary" and "testing" are not defined enough to support the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - 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	
Response	
Colleen Campbell - 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	
Response	
Shannon Mickens - 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	
Response	
David Bueche - 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	
Response	
Elizabeth Axson - 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	
Response	
Colby Bellville - 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	
Response	
sean erickson - 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	
Response	

Stephanie Burns - 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	
Response	

Stephanie Burns - 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	
Response	

Chris Gowder - 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	
Response	

Pamela Hunter - 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	
Response	
Dennis Chastain - 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	
Response	
Michelle Amarantos - 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	
Response	
Paul Mehlhaff - 1	
Answer	No
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	
Response	
Jaclyn Massey - 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	
Response	
Oliver Burke - 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	
Response	
Tom Hanzlik - 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	
Response	
John Williams - 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	
Response	
Emily Rousseau - 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	
Response	
Scott Langston - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - 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	
Response	
Oshani Pathirane - 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	
Response	
Matthew Beilfuss - 1,3,4,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - 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	
Response	
Terry Harbour - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

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

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

Response	
Rachel Coyne - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

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

Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brad Lisembee - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Nail - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	
Document Name	
Comment	
No opinion	
Likes 0	
Dislikes 0	
Response	

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.

Justin Wilderness - 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	
Response	
Paul Mehlhaff - 1	
Answer	No
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - 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	
Response	
Diana McMahon - 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	
Response	
Colby Bellville - 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	
Response	
Colleen Campbell - 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	
Response	
Laurie Williams - 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	
Response	
Oliver Burke - 1	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jaclyn Massey - 5	
Answer	Yes
Document Name	
Comment	
No comments	

Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - 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	
Response	
Stephanie Burns - 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	
Response	
Stephanie Burns - 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	

Response	
Rachel Coyne - 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	
Response	
Shannon Mickens - 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	

Response	
Matthew Beilfuss - 1,3,4,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - 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	
Response	
Shawn Abrams - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - 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	
Response	
ALAN ADAMSON - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Nail - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Williams - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

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

Comment	
Likes 0	
Dislikes 0	
Response	
David Kiguel - 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawna Speer - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Pamela Hunter - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Chris Gowder - 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	

Response

Quintin Lee - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Ruida Shu - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5;	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - 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	
Response	
Gregory DAnnibale - NA - Not Applicable - NPCC	
Answer	
Document Name	

Comment	
No opinion	
Likes 0	
Dislikes 0	
Response	

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

Douglas Webb - 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	
Response	
Laurie Williams - 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	
Response	
Chris Scanlon - 1	
Answer	

Document Name	
Comment	
See above, quarterly vs monthly schedule . Thank you.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - 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	
Response	
Shawn Abrams - 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	
Response	
Jamie Monette - 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	

Response

Colleen Campbell - 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	

Response

Matthew Beilfuss - 1,3,4,6 - MRO,RF

Answer	
Document Name	
Comment	

N/A

Likes 0	
Dislikes 0	

Response

Shannon Mickens - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - 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	

Response

Gregory DAnnibale - NA - Not Applicable - NPCC

Answer	
Document Name	

Comment

No opinion

Likes 0	
Dislikes 0	

Response

Chris Gowder - 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	

Response

Sergio Banuelos - 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	
Response	
Dennis Chastain - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Paul Mehlhaff - 1	
Answer	
Document Name	
Comment	
Sunflower is signing on in support of ACES comments.	
Likes 0	
Dislikes 0	
Response	
Jaclyn Massey - 5	
Answer	
Document Name	

Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - 1	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Joshua Smith - 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	
Response	
Ginette Lacasse - 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	
Response	
Emily Rousseau - 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	
Response	
Jim Nail - 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	
Response	
Thomas Foltz - 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	
Response	

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016
45-day formal comment period with ballot	June 20 - August 3, 2016

Anticipated Actions	Date
45-day formal comment period with additional ballot	September 2016
10-day final ballot	November 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-5
3. **Purpose:** To provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability:**
    4.1. Functional Entities:
        4.1.1. Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirements R1 and R2: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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) primary 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. 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.

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 additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the RC's primary Control Center is not addressed by the proposed requirement.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

Rationale for Requirement R3: The revised requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R3. Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R3. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

R5. Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator’s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R4 and Measures M1, M2, and M4.
- The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 and Measures M5 and M6 for the current calendar year and one previous calendar year.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2.	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, as specified in the requirement.	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.
R3.	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	capabilities specified in Requirement R2 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Reliability Coordinator did not test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action to restore the redundant functionality in more than 8 hours.
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
R5.	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6.	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:
The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:
Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 (R6 in IRO-002-5) has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for R4 (R6 in IRO-002-5):
The requirement was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016
45-day formal comment period with ballot	June 20 - August 3, 2016

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~June 2016~~
45-day formal comment period with additional ballot	September 2016
10-day final ballot	November 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-5
3. **Purpose:** To provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirements R1 and R2: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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~~primary 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. 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 ~~Control Center~~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 additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the RC's ~~Control Center~~primary Control Center is not addressed by the proposed requirement.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other~~a~~ documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's ~~Control Center~~primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

Rationale for Requirement R3: The revised requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R3. Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R3. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

R5. Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R4 and Measures M1, M2, and M4.
- The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 and Measures M5 and M6 for the current calendar year and one previous calendar year.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2.	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's ~~Control Center~~primary Control Center, as specified in the requirement.	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.
R3.	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange

	capabilities specified in Requirement R2 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Reliability Coordinator did not test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality ~~at least once each calendar month~~; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, did not initiate action to restore the redundant functionality in more than 8 hours.
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its

				telecommunication, monitoring and analysis capabilities.
R5.	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6.	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:

The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:

Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 (R6 in IRO-002-5) has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for R4 (R6 in IRO-002-5):

The ~~R~~requirement ~~R6~~ was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-~~4~~5
3. **Purpose:** To ~~Provide~~ provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability**

   4.1. Functional Entities

   ~~4.1.~~4.1.1 Reliability Coordinator
5. **Effective Date:**

   See Implementation Plan~~.~~

~~6. **Background:**~~

~~See the Project 2014~~2016~~-03~~ 01.

B. Requirements and Measures

Rationale for Requirements R1 and R2: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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) primary 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. 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.

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 additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the RC's primary Control Center is not addressed by the proposed requirement.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments~~. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its ~~operational~~ Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments~~.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other~~a~~ documentation that lists its data exchange capabilities, ~~with~~including redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

Rationale for Requirement R3: The revised requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R3. Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once

~~each~~every 90 calendar ~~month~~days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality,~~;~~ or experienced an event that demonstrated the redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R3. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

~~R2.~~R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

~~M1.~~M4. Each Reliability Coordinator shall, have and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

~~R3.~~R5. Each Reliability Coordinator shall monitor Facilities, the status of ~~Special Protection System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any -System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of ~~Special Protection System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

~~R4.~~R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~**1.2. Compliance Monitoring and Assessment Processes:**~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~1.2. ~~Data~~ Evidence Retention

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

~~The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and ~~R3~~R4 and Measures M1, M2, and ~~M3~~M4.

The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 ~~R4~~ and Measures M5 and M6 ~~M4~~ for the current calendar year and one previous calendar year.

~~If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.~~

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~**1.4. Additional Compliance Information**~~

~~None.~~

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, as specified in the requirement.	
R3	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Reliability Coordinator did not test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality ~~at least once each calendar month~~; OR The Reliability Coordinator tested its primary Control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, did not initiate action to restore the redundant functionality in more than 8 hours.
~~R2~~R4	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
~~R3~~R5	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of ~~Special Protection~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
~~R4~~R6	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The Implementation Plan and other project documents can be found on the project page.~~None.~~

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised

3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

~~**Rationale:**~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:
The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The ~~SDT~~Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:
Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 (R6 in IRO-002-5) has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for R4 (R6 in IRO-002-6):

The ~~R~~requirement ~~R4~~ ~~R6~~ was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016
45-day formal comment period with ballot	June 20 - August 3, 2016

Anticipated Actions	Date
45-day formal comment period with additional ballot	September 2016
10-day final ballot	November 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Transmission Operations**
2. **Number:** TOP-001-4
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.2. Transmission Operator

   4.1.3. Generator Operator

   4.1.4. Distribution Provider

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the

Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not

limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

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 Transmission Operator 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.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area

and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a

SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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 Transmission Operator's (TOP) primary 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. 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'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 additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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 to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Rationale for Requirements R22 and R23: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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 Balancing Authority's (BA) primary 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. Requirement R23 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 BA'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 additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

R22. Each Balancing Authority shall have data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M22. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 to perform its Real-time monitoring and analysis functions as specified in the requirement.

Rationale for Requirement R24: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.
- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R20, and Measure M15 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall each keep data or evidence for each applicable Requirement R22 through R23, and Measure M22 through M23 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items	The Transmission Operator did not monitor, obtain, or utilize two of the items required or	The Transmission Operator did not monitor, obtain, or utilize three of the items required or	The Transmission Operator did not monitor, obtain, or utilize four or more of the items

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.
R11	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Center, as specified in the Requirement.	
R21	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				functionality in more than 8 hours.
R22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, as specified in the Requirement.	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.
R24	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test;

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is:
http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	
4	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016
45-day formal comment period with ballot	June 20 - August 3, 2016

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~June 2016~~
45-day formal comment period with additional ballot	September 2016
10-day final ballot	November 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Transmission Operations**
2. **Number:** TOP-001-4
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
     - **4.1.2.** Transmission Operator
     - **4.1.3.** Generator Operator
     - **4.1.4.** Distribution Provider
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the

Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings,

electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The~~se~~ facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

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 Transmission Operator 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.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its ~~Operational Planning Analyses~~OPAs, Real-time monitoring, and ~~Real-time Assessment~~RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area

and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

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

If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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 Transmission Operator's (TOP) ~~Control Center~~primary 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. 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's ~~Control Center~~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 additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the TOP's ~~Control Center~~primary Control Center is not addressed by the proposed requirement.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, ~~operator logs,~~ system specifications, system diagrams, or other ~~evidence~~ documentation that lists its ~~that it has~~ data exchange capabilities, ~~with~~ including redundant and diversely routed data exchange infrastructure within the Transmission Operator's ~~Control Center~~primary 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 to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Rationale for Requirements R22 and R23: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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 Balancing Authority's (BA) ~~Control Center~~primary 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. Requirement R23 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 BA's ~~Control Center~~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 additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the BA's ~~Control Center~~primary Control Center is not addressed by the proposed requirement.

R22. Each Balancing Authority shall have data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M22. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, ~~operator logs,~~ system specifications, system diagrams, or other ~~evidence~~ documentation that ~~it has~~lists its data exchange capabilities, ~~with~~ including redundant and diversely routed data exchange infrastructure within the Balancing Authority's ~~Control Center~~primary Control Center, 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 to perform its Real-time monitoring and analysis functions as specified in the requirement.

Rationale for Requirement R24: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.

- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R20, and Measure M15 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall each keep data or evidence for each applicable Requirement R22 through R23, and Measure M22 through M23 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Instruction issued by its Transmission Operator.
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				safety, equipment, regulatory, or statutory requirements.
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities,	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	channels between the affected entities.	channels between the affected entities.		telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.
R11	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Area and support Interconnection frequency.	
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				instances where there was a difference in SOLs.
R19	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's ~~Control~~	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~Center~~primary Control Center, as specified in the Requirement.	
R21	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once ~~each~~ every 90	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test,	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality ~~at least once each calendar month~~; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once ~~each~~ every 90

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	functionality in more than 6 hours and less than or equal to 8 hours.	calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.
R22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's ~~Control Center~~primary Control Center, as specified in the Requirement.	functions as specified in the Requirement.
R24	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality ~~at least once each calendar month~~; OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	in Requirement R23 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is:
http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	
4	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

A. Introduction

1. **Title: Transmission Operations**
2. **Number: TOP-001-~~3~~4**
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   4.1. Balancing Authority
   4.2. Transmission Operator
   4.3. Generator Operator
   4.4. Distribution Provider
5. **Effective Date:**
   See Implementation Plan~~.~~

~~6. Background:~~

~~See Project 2014-03 project page.~~

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and

provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings,

electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

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 Transmission Operator 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.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

R10. Each Transmission Operator shall perform the following ~~as necessary~~ for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. ~~Within its Transmission Operator Area, monitor~~ Monitor Facilities within its Transmission Operator Area; ~~and~~

10.2. Monitor the status of ~~Special Protection Systems~~Remedial Action Schemes within its Transmission Operator Area;

~~10.1.~~10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;~~and~~

10.4. ~~Outside its Transmission Operator Area, o~~Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

~~**10.2.** and the status of Special Protection Systems.~~

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized ~~status, voltages, and flow~~ data ~~for Facilities and the status of~~

~~Special Protection Systems~~ as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

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

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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 Transmission Operator's (TOP) primary 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. 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'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 additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses.~~the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.~~ *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Transmission Operator Area~~perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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]

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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 to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Rationale for Requirements R22 and R23: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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 Balancing Authority's (BA) primary 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. Requirement R23 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 BA'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 additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

~~R20.~~R22. Each Balancing Authority shall have data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to develop its Operating Plan for next-day operations.~~maintain reliability in its Balancing Authority Area.~~ *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M22~~0~~. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Balancing Authority Area~~develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary

Control Center, 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 to perform its Real-time monitoring and analysis functions as specified in the requirement.

Rationale for Requirement R24: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~As defined in the NERC Rules of Procedure,~~ "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable ~~the NERC~~ Reliability Standards in their respective jurisdictions.

~~**1.2. Compliance Monitoring and Assessment Processes**~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be~~

~~used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~1.2. ~~Data~~ Evidence Retention

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full time period since the last audit.~~

Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and ~~R15 through R20 and~~ Measure M1 through M11~~, and M15 through M20~~ for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ~~ninety~~ 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.

~~and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.~~

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

Each Transmission Operator shall retain evidence ~~and~~ that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.

Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R20, and Measure M15 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Balancing Authority shall each keep data or evidence for each applicable Requirement R22 through R23, and Measure M22 through M23 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

~~If a Balancing Authority, Transmission Operator, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.~~

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~**1.4. Additional Compliance Information**~~

~~None.~~

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities,	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Emergency on respective Balancing Authority Areas.	resulted in, an Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.~~N/A~~	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1~~.~~ through 10.6. ~~OR,~~ ~~The Transmission Operator did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.~~	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6 ~~and did not obtain and utilize one of the items listed in Requirement R10, Part 10.2~~.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.~~Facilities and the status of Special Protection Systems within its Transmission Operator Area and did not obtain and utilize data deemed as necessary from outside its Transmission Operator Area.~~
R11	N/A	N/A	The Balancing Authority did not monitor the status of ~~Special Protection System~~Remedial Action Schemes that impact	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	support Interconnection frequency.
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, as specified in the Requirement.	
R21	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality; OR The Transmission Operator tested its primary Control Center data exchange

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.
~~R20~~R22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange	The Balancing Authority did not have data exchange

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, as specified in the Requirement.	capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.
R24	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test;	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The ~~SDT~~Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	
4	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

~~**Rationale:**~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

Implementation Plan

Project 2016-01 Modifications to TOP and IRO Standards
Reliability Standards IRO-002-5 and TOP-001-4

Applicable Standard(s)

- IRO-002-5 - Reliability Coordination - Monitoring and Analysis
- TOP-001-4 - Transmission Operations

Requested Retirement(s)

- IRO-002-4 - Reliability Coordination - Monitoring and Analysis
- TOP-001-3 - Transmission Operations

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

On November 19, 2015, the Federal Energy Regulatory Commission (FERC) issued Order No. 817 approving nine revised or new TOP and IRO Reliability Standards from Project 2014-03 that addressed previously-identified reliability issues and concerns. In approving the standards, FERC also directed development of modifications to TOP and IRO standards to address specific concerns related to: (i) Transmission Operator monitoring of some non-Bulk Electric System (non-BES) elements needed for reliable operations, and (ii) redundancy in data exchange capabilities used by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable operations.

General Considerations

The three-month implementation period for IRO-002-5 provides Reliability Coordinators with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality. The proposed implementation plan presumes that IRO-002-4 is effective, or will become effective, on or before the effective date of IRO-002-5.

The 12-month implementation period for TOP-001-4 provides Transmission Operators (TOP) with time to revise and distribute data specifications required by TOP-003-3 Requirement R1 to include non-BES data identified by the TOP, and receive data from entities responsible for providing the data as required by TOP-003-3 Requirement R5. The implementation period also provides TOPs and Balancing Authorities (BAs) with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality.

Effective Date

IRO-002-5
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-001-4
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

IRO-002-4
Reliability Standard IRO-002-4 shall be retired immediately prior to the effective date of IRO-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

TOP-001-3
Reliability Standard TOP-001-3 shall be retired immediately prior to the effective date of TOP-001-4 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

IRO-002-5
The initial test of primary Control Center data exchange capabilities specified in Requirement R3 must be completed within 90 calendar days of the effective date of IRO-002-5.

TOP-001-4
The initial test of primary Control Center data exchange capabilities specified in Requirements R21 and R24 must be completed within 90 calendar days of the effective date of TOP-001-4.

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Implementation Plan

Project 2016-01 Modifications to TOP and IRO Standards
Reliability Standards IRO-002-5 and TOP-001-4

Applicable Standard(s)

- IRO-002-5 - Reliability Coordination - Monitoring and Analysis
- TOP-001-4 - Transmission Operations

Requested Retirement(s)

- IRO-002-4 - Reliability Coordination - Monitoring and Analysis
- TOP-001-3 - Transmission Operations

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

On November 19, 2015, the Federal Energy Regulatory Commission (FERC) issued Order No. 817 approving nine revised or new TOP and IRO Reliability Standards from Project 2014-03 that addressed previously-identified reliability issues and concerns. In approving the standards, FERC also directed development of modifications to TOP and IRO standards to address specific concerns related to: (i) Transmission Operator monitoring of some non-Bulk Electric System (non-BES) elements needed for reliable operations, and (ii) redundancy in data exchange capabilities used by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable operations.

General Considerations

The three-month implementation period for IRO-002-5 provides Reliability Coordinators with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality. The proposed implementation plan presumes that IRO-002-4 is effective, or will become effective, on or before the effective date of IRO-002-5.

The 12-month implementation period for TOP-001-~~3~~ 4 provides Transmission Operators (TOP) with time to revise and distribute data specifications required by TOP-003-3 Requirement R1 to include non-BES data identified by the TOP, and receive data from entities responsible for providing the data as required by TOP-003-3 Requirement R5. The implementation period also provides TOPs and Balancing Authorities (BAs) with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality.

Effective Date

IRO-002-5
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-001-4
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

IRO-002-4
Reliability Standard IRO-002-4 shall be retired immediately prior to the effective date of IRO-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

TOP-001-3
Reliability Standard TOP-001-3 shall be retired immediately prior to the effective date of TOP-001-4 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

IRO-002-5
The initial test of primary Control Center data exchange capabilities specified in Requirement R3 must be completed within 90 calendar days of the effective date of IRO-002-5.

TOP-001-4
The initial test of primary Control Center data exchange capabilities specified in Requirements R21 and R24 must be completed within 90 calendar days of the effective date of TOP-001-4.

Unofficial Comment Form

Project 2016-01 Modifications to TOP and IRO Standards

Do not use this form for submitting comments. Use the electronic form to submit comments on **IRO-002-5 – Reliability Coordination - Monitoring and Analysis** and **TOP-001-4 – Transmission Operations**. The electronic form must be submitted by **8 p.m. Eastern, October 14, 2016.**

Additional information about this project is available on the Project 2016-01 Modifications to TOP and IRO Standards project page. If you have questions, contact Standards Developer, Mark Olson (via email), or at (404) 446-9760.

Background Information

On November 19, 2015, the Federal Energy Regulatory Commission (FERC) issued Order No. 817 approving revised TOP and IRO standards and directing modifications to address the following reliability concerns:

- Transmission Operator (TOP) monitoring of non-Bulk Electric System (BES) facilities as necessary for reliability (P. 35);
- Redundancy and diverse routing of data exchange capabilities used by Reliability Coordinators (RC), Balancing Authorities (BA), and TOPs (P. 47); and
- Testing of alternate data exchange capabilities used in RC, TOP, and BA control centers (P. 51).

FERC established a deadline of July 2017 for NERC to file modifications to standards addressing the above directives.

Proposed IRO-002-5 and TOP-001-4 contain revised and new requirements addressing the Order No. 817 directives. Proposed IRO-002-5 received sufficient stakeholder support in the initial posting to proceed to final ballot, however the Standard Drafting Team (SDT) has incorporated revisions suggested by industry. Proposed TOP-001-4 did not receive sufficient stakeholder support and has also been revised. The SDT's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Questions

1. Do you agree with the changes made by the SDT to draft standard IRO-002-5? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.
   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the changes made by the SDT to draft standard TOP-001-4? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.
   ☐ Yes
   ☐ No

   Comments:

3. 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.
   ☐ Yes
   ☐ No

   Comments:

4. 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.
   ☐ Yes
   ☐ No

   Comments:

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

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-01 - Modifications to TOP and IRO Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Reliability Standard requirements developed in Project 2016-01. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. 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.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

Project 2016-01 Reliability Standards Requirements

The SDT developed new or revised requirements in IRO-002-5 and TOP-001-4 to address reliability objectives outlined in the project Standard Authorization Request (SAR). The VRF and VSL justification for these new and revised requirements is described below. VRF and VSL justification for requirements that were not modified in Project 2016-01 can be found on the Project 2014-03 Project Page.

VRF Justification

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirement is not directly connected to an area identified in the Blackout Report.

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The proposed VRF is unchanged from approved TOP-001-3 Requirement R10. Additionally, the requirement is similar to approved IRO-002-4 Requirement R3 which applies to Reliability Coordinators and is assigned a High VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement addresses a single reliability objective and has a single VRF.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Operations Planning time horizon, which are not the subject of the Blackout Report recommendations regarding data exchange. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements address data exchange capabilities for the Operations Planning time horizon only, which is a significant change from approved IRO-002-4 Requirement R1 and TOP-001-3 Requirements R19 and R20 which apply to all operations time horizons. As proposed, the VRF will establish consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a Medium VRF. Failure to have data exchange capabilities necessary for performing Operational Planning Analysis or for developing an Operating Plan for next day operations could directly and adversely affect the electrical state or capability of the BES, or the ability to effectively control or restore the BES. However, this failure is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Same-day Operations and Real-time Operations time horizons. A High VSL is assigned to reflect the potential impact on the reliability of the BES consistent with the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements improve upon requirements for data exchange capabilities in approved IRO-002-4 and TOP-001-3, which are assigned a High VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a High VRF. Failure to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the primary Control Center, for performing Real-time monitoring and analysis could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
Proposed VRF	Medium
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements are not directly connected to an area identified in the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	These are new requirements. Approved COM-001-2.1 Requirement R9 requires periodic testing of Alternate Interpersonal Communications capability and is assigned a Medium VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5, proposed TOP-001-4, and approved COM-001-2.1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for Medium VRF. Failure to periodically test primary Control Center data exchange capabilities for redundant functionality could, under anticipated data exchange infrastructure failure, affect the ability to monitor and control the BES. However, failure to test primary Control Center data exchange capabilities for redundant functionality is not likely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VSL Justification

VSLs for TOP-001-4 Requirement R10			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

VSL Justifications for TOP-001-4 Requirement R10	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved TOP-001-3 Requirement R10.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for TOP-001-4 Requirement R10	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22			
Lower	**Moderate**	**High**	**Severe**
The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with one identified entity, or 5% or less of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with two identified entities, or more than 5% or less than or equal to 10% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with three identified entities, or more than 10% or less than or equal to 15% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with four or more identified entities or greater than 15% of the identified entities, whichever is greater.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved IRO-002-4 Requirement R1 and approved TOP-001-3 Requirements R19 and R20.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The applicable entity had data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), but did not have redundant and diversely routed data exchange infrastructure	The applicable entity did not have data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), as specified in the Requirement.

		within its primary Control Center, as specified in the Requirement.	

VSL Justifications for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24			
Lower	**Moderate**	**High**	**Severe**
The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 180 calendar days since the previous test; OR The applicable entity did not test its primary Control Center data exchange capabilities for redundant functionality; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-01 - Modifications to TOP and IRO Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Reliability Standard requirements developed in Project 2016-01. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. 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.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

Project 2016-01 Reliability Standards Requirements

The SDT developed new or revised requirements in IRO-002-5 and TOP-001-4 to address reliability objectives outlined in the project Standard Authorization Request (SAR). The VRF and VSL justification for these new and revised requirements is described below. VRF and VSL justification for requirements that were not modified in Project 2016-01 can be found on the Project 2014-03 Project Page.

VRF Justification

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirement is not directly connected to an area identified in the Blackout Report.

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The proposed VRF is unchanged from approved TOP-001-3 Requirement R10. Additionally, the requirement is similar to approved IRO-002-4 Requirement R3 which applies to Reliability Coordinators and is assigned a High VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement addresses a single reliability objective and has a single VRF.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Operations Planning time horizon, which are not the subject of the Blackout Report recommendations regarding data exchange. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements address data exchange capabilities for the Operations Planning time horizon only, which is a significant change from approved IRO-002-4 Requirement R1 and TOP-001-3 Requirements R19 and R20 which apply to all operations time horizons. As proposed, the VRF will establish consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a Medium VRF. Failure to have data exchange capabilities necessary for performing Operational Planning Analysis or for developing an Operating Plan for next day operations could directly and adversely affect the electrical state or capability of the BES, or the ability to effectively control or restore the BES. However, this failure is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Same-day Operations and Real-time Operations time horizons. A High VSL is assigned to reflect the potential impact on the reliability of the BES consistent with the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements improve upon requirements for data exchange capabilities in approved IRO-002-4 and TOP-001-3, which are assigned a High VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a High VRF. Failure to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the primary Control Center, for performing Real-time monitoring and analysis could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements are not directly connected to an area identified in the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	These are new requirements. Approved COM-001-2.1 Requirement R9 requires periodic testing of Alternate Interpersonal Communications capability and is assigned a Medium VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5, proposed TOP-001-4, and approved COM-001-2.1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for Medium VRF. Failure to periodically test primary Control Center data exchange capabilities for redundant functionality could, under anticipated data exchange infrastructure failure, affect the ability to monitor and control the BES. However, failure to test primary Control Center data exchange capabilities for redundant functionality is not likely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VSL Justification

VSLs for TOP-001-4 Requirement R10			
Lower	Moderate	High	Severe
The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

VSL Justifications for TOP-001-4 Requirement R10	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved TOP-001-3 Requirement R10.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for TOP-001-4 Requirement R10	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22

Lower	Moderate	High	Severe
The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with one identified entity, or 5% or less of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with two identified entities, or more than 5% or less than or equal to 10% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with three identified entities, or more than 10% or less than or equal to 15% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with four or more identified entities or greater than 15% of the identified entities, whichever is greater.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved IRO-002-4 Requirement R1 and approved TOP-001-3 Requirements R19 and R20.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The applicable entity had data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), but did not have redundant and diversely routed data exchange infrastructure	The applicable entity did not have data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), as specified in the Requirement.

		within its primary Control Center, as specified in the Requirement.	

VSL Justifications for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24			
Lower	**Moderate**	**High**	**Severe**
The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 180 calendar days since the previous test; OR The applicable entity did not test its primary Control Center data exchange capabilities for redundant functionality ~~at least once each calendar month~~; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

Order No. 817 Citation	Directive/Guidance	Resolution
P 35	Revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities.	The directive is addressed in proposed TOP-001-4 Requirement R10. Parts 10.3 and 10.6 cover non-BES facilities. ***Proposed TOP-001-4*** **R10.** Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.1.** Monitor Facilities within its Transmission Operator Area; **10.2.** Monitor the status of Remedial Action Schemes within its Transmission Operator Area; **10.3.** Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator; **10.4.** Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator; **10.5.** Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and **10.6.** Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

Order No. 817 Citation	Directive / Guidance	Resolution
P 47	Modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing. In addition, [the Commission directs] NERC to clarify that "redundant infrastructure" for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.	Proposed TOP-001-4 Requirements R20 and R23 address the directive for Transmission Operators (TOP) and Balancing Authorities (BA), respectively. For consistency, the Standards Drafting Team (SDT) developed proposed IRO-002-5 Requirement R2 to address the directive for Reliability Coordinators (RCs) rather than develop a modification to IRO-002-4 Requirement R4. ***Proposed TOP-001-4*** **R20.** Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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. **R23.** Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 analysis functions. ***Proposed IRO-002-5*** **R2.** Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators,

Order No. 817 Citation	Directive / Guidance	Resolution
		and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments.
P 51	Develop a modification to the TOP and IRO standards that 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.	The directive is addressed in proposed TOP-001-4 Requirements R21 and R24, and proposed IRO-002-5 Requirement R3. ***Proposed TOP-001-3*** **R21.** Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. **R24.** Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. ***Proposed IRO-002-5*** **R3.** Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality.

Standards Announcement Reminder

Project 2016-01 Modifications to TOP and IRO Standards IRO-002-5 and TOP-001-4

Additional Ballots and Non-binding Polls Open through October 14, 2016

Now Available

Additional ballots for **IRO-002-5 – Reliability Coordination - Monitoring and Analysis** and **TOP-001-4 – Transmission Operations** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Friday, October 14, 2016**.

Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards and non-binding polls here. If you experience any difficulties in using the electronic form, contact Wendy Muller.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

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Standards Announcement

Project 2016-01 Modifications to TOP and IRO Standards
IRO-002-5 and TOP-001-4

Formal Comment Period Open through October 14, 2016

Now Available

A 45-day formal comment period for **IRO-002-5 – Reliability Coordination - Monitoring and Analysis** and **TOP-001-4 – Transmission Operations** is open through **8 p.m. Eastern, Friday, October 14, 2016**.

This is the second posting of the proposed standards. Proposed IRO-002-5 received sufficient stakeholder support in the previous posting to proceed to final ballot, however the Standard Drafting Team (SDT) has incorporated revisions suggested by industry. Proposed TOP-001-4 did not receive sufficient stakeholder support and has also been revised. The SDT's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Commenting

Use the electronic form to submit comments on the standards. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

Additional ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 5-14, 2016**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/65)
Ballot Name: 2016-01 Modifications to TOP and IRO Standards IRO-002-5 AB 2 ST
Voting Start Date: 10/5/2016 12:01:00 AM
Voting End Date: 10/17/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 225
Total Ballot Pool: 269
Quorum: 83.64
Weighted Segment Value: 70.77

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	65	1	30	0.732	11	0.268	0	13	11
Segment: 2	8	0.6	4	0.4	2	0.2	0	1	1
Segment: 3	59	1	27	0.675	13	0.325	0	9	10
Segment: 4	17	1	7	0.583	5	0.417	0	3	2
Segment: 5	61	1	28	0.757	9	0.243	0	10	14
Segment: 6	45	1	21	0.636	12	0.364	0	7	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	2	0.2	1	0.1	1	0.1	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.9	8	0.8	1	0.1	0	0	0
Totals:	269	6.9	128	4.883	54	2.017	0	43	44

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Abstain	N/A
1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Shawna Speer		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Abstain	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Negative	Third-Party Comments
1	Western Area Power Administration	sean erickson		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Abstain	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Sing Tay	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	Thomas Lyons		Abstain	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		None	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		None	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Westar Energy	Bo Jones		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Abstain	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		None	N/A
5	NB Power Corporation	Laura McLeod		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Negative	Third-Party Comments
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Chris Janick		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 269 of 269 entries

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/65)
Ballot Name: 2016-01 Modifications to TOP and IRO Standards TOP-001-4 AB 2 ST
Voting Start Date: 10/5/2016 12:01:00 AM
Voting End Date: 10/17/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 247
Total Ballot Pool: 301
Quorum: 82.06
Weighted Segment Value: 68.85

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	37	0.661	19	0.339	0	6	13
Segment: 2	8	0.6	4	0.4	2	0.2	0	1	1
Segment: 3	66	1	33	0.647	18	0.353	0	3	12
Segment: 4	19	1	10	0.625	6	0.375	0	0	3
Segment: 5	70	1	34	0.708	14	0.292	0	4	18
Segment: 6	49	1	25	0.61	16	0.39	0	2	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	2	0.2	1	0.1	1	0.1	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.9	8	0.8	1	0.1	0	0	0
Totals:	301	6.9	154	4.751	77	2.149	0	16	54

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	American Transmission Company, LLC	Andrew Pusztai		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Shawna Speer		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Stanley Beasley	None	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Affirmative	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Negative	Third-Party Comments
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Negative	Third-Party Comments
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Mark Holman		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth	Todd Komaromy	Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Third-Party Comments
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Sing Tay	Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Negative	Comments Submitted
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		None	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Negative	Third-Party Comments
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	Acciona Energy North America	George Brown		None	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Affirmative	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		None	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	SunPower	Bradley Collard		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Negative	Third-Party Comments
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Third-Party Comments
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Chris Janick		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Showing 1 to 301 of 301 entries

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/65)
Ballot Name: 2016-01 Modifications to TOP and IRO Standards IRO-002-5 Non-binding Poll AB 2 NB
Voting Start Date: 10/5/2016 12:01:00 AM
Voting End Date: 10/17/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 209
Total Ballot Pool: 255
Quorum: 81.96
Weighted Segment Value: 68.67

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	61	1	25	0.714	10	0.286	0	16	10
Segment: 2	7	0.3	2	0.2	1	0.1	0	3	1
Segment: 3	59	1	24	0.686	11	0.314	0	13	11
Segment: 4	15	0.9	6	0.6	3	0.3	0	4	2
Segment: 5	58	1	21	0.7	9	0.3	0	12	16
Segment: 6	41	1	16	0.593	11	0.407	0	9	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	2	0.2	1	0.1	1	0.1	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.7	6	0.6	1	0.1	0	2	0
Totals:	255	6.3	103	4.393	47	1.907	0	59	46

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Shawna Speer		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Abstain	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Michael DeLoach		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Abstain	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Abstain	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Sing Tay	Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Abstain	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		None	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		None	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		Abstain	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Abstain	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City of Independence, Power and Light Department	Jim Nail		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		None	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Puget Sound Energy, Inc.	Lynda Kupfer		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Westar Energy	stephanie johnson		Negative	Comments Submitted
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Chris Janick		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Westar Energy	Megan Wagner		Negative	Comments Submitted
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Showing 1 to 255 of 255 entries

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/65)
Ballot Name: 2016-01 Modifications to TOP and IRO Standards TOP-001-4 Non-binding Poll AB 2 NB
Voting Start Date: 10/5/2016 12:01:00 AM
Voting End Date: 10/17/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 223
Total Ballot Pool: 276
Quorum: 80.8
Weighted Segment Value: 67.98

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	68	1	28	0.683	13	0.317	0	14	13
Segment: 2	7	0.3	2	0.2	1	0.1	0	3	1
Segment: 3	64	1	28	0.667	14	0.333	0	9	13
Segment: 4	16	1	8	0.727	3	0.273	0	3	2
Segment: 5	64	1	26	0.703	11	0.297	0	9	18
Segment: 6	43	1	20	0.606	13	0.394	0	5	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	2	0.2	1	0.1	1	0.1	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.7	6	0.6	1	0.1	0	2	0
Totals:	276	6.4	121	4.486	57	1.914	0	45	53

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Colorado Springs Utilities	Shawna Speer		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Stanley Beasley	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Affirmative	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	None	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Michael DeLoach		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth	Todd Komaromy	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Sing Tay	Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Negative	Comments Submitted
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Abstain	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Abstain	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	Acciona Energy North America	George Brown		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Abstain	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Affirmative	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		None	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Kevin Nielsen		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	SunPower	Bradley Collard		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Westar Energy	stephanie johnson		Negative	Comments Submitted
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Chris Janick		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Megan Wagner		Negative	Comments Submitted
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 276 of 276 entries

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2016-01 Modifications to TOP and IRO Standards
IRO-002-5 and TOP-001-4

Formal Comment Period Open through October 14, 2016

Now Available

A 45-day formal comment period for **IRO-002-5 – Reliability Coordination - Monitoring and Analysis** and **TOP-001-4 – Transmission Operations** is open through **8 p.m. Eastern, Friday, October 14, 2016**.

This is the second posting of the proposed standards. Proposed IRO-002-5 received sufficient stakeholder support in the previous posting to proceed to final ballot, however the Standard Drafting Team (SDT) has incorporated revisions suggested by industry. Proposed TOP-001-4 did not receive sufficient stakeholder support and has also been revised. The SDT's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Commenting

Use the electronic form to submit comments on the standards. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

Additional ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 5-14, 2016**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2016-01 Modifications to TOP and IRO Standards | IRO-002-5 and TOP-001-4
Comment Period Start Date:	8/31/2016
Comment Period End Date:	10/17/2016
Associated Ballots:	2016-01 Modifications to TOP and IRO Standards IRO-002-5 AB 2 ST 2016-01 Modifications to TOP and IRO Standards IRO-002-5 Non-binding Poll AB 2 NB 2016-01 Modifications to TOP and IRO Standards TOP-001-4 AB 2 ST 2016-01 Modifications to TOP and IRO Standards TOP-001-4 Non-binding Poll AB 2 NB

There were 40 sets of responses, including comments from approximately 37 different people from approximately 36 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the changes made by the SDT to draft standard IRO-002-5? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

2. Do you agree with the changes made by the SDT to draft standard TOP-001-4? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

3. 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.

4. 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.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP 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
					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
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
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
					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
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
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 and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no National Grid	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					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
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Sean Bodkin	Dominion	4	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Darryl Boggess	Western Farmers	1,5	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					J. Scott Williams	City Utilities of Springfield	1,4	SPP RE
					Jim Nail	Independence Power and Light	3	SPP RE
					Jerry McVey	Sunflower	1	SPP RE
					John Allen	City Utilities of Springfield	1,4	SPP RE
					Kevin Giles	Westar Energy	1,3,5,6	SPP RE

					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Michelle Corley	Cleco Coporation	1,3,5,6	SPP RE
					Robert Hirchak	Cleco Coporation	1,3,5,6	SPP RE
					David Pham	Empire District Electric Company	1,3,5	SPP RE
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. Do you agree with the changes made by the SDT to draft standard IRO-002-5? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
We believe that Requirement R5 should identify how these non-BES facilities are determined, such as through Seasonal Assessments and other Monthly Analysis. In our opinion, in no case should this be left open ended, without bounds.	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Xcel Energy believes that there is still some clarification needed to the definition of data exchange. Is it meant to cover data exchange between control centers (ICCP) or does this include RTUs and Communication paths?	
Likes 0	
Dislikes 0	
Response	

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller	
Answer	No
Document Name	
Comment	
Comments: See comments below. MEAG Power voted Affirmative in error and requests that its Affirmative vote be changed to Negative for all associated ballots, Standard changes and Non-Binding opinions. MEAG Power adopts and supports the comments of Southern Company.	

Regards,

Scott Miller, Proxy, MEAG Power, 678-644-3524

Likes 0	
Dislikes 0	

Response

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 limiting the scope of Requirement R2 to “the data exchange infrastructure inside the Primary Control Center” may allow for entities to circumvent the requirements by moving their data exchange infrastructure to a physical location outside of their control center (i.e., a remote data center). It is important for the SDT to ensure the reliability intent of Requirement R2 is maintained by focusing on the “data exchange capability” for the primary control center regardless of where the actual data exchange infrastructure physically resides. To remove any ambiguity, it is recommended that the SDT define the following terms:

- Data Exchange Infrastructure
- Data Exchange Capability
- Primary Control Center

In regard to R3, it is Southern Company's understanding that in most cases (including ours) that the data exchange infrastructure is an integrated component of the EMS infrastructure. Southern Company does not understand the purpose of having a requirement for redundant infrastructure for data exchange but not for the EMS.

Southern Company also requests clarification regarding the language used in IRO-002-5 R6, which states “each RC shall have monitoring systems that provide information utilized by the RC’s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.” Some questions regarding the proposed requirement are as follows:

- What is meant by “particular emphasis”?
- Which “awareness systems” require redundant infrastructure?
- Which “automated data transfers” are in scope?
- Which “synchronized information” is in scope?

- What level of redundancy is required? Server level, component level, network level, etc.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no National Grid

Answer	No
Document Name	

Comment

The requirements should apply to “secondary” Control Centers as well. There are times when a primary Control Center might be out of service for a prolonged length of time, and the “secondary” Control Center must have the capabilities addressed by this standard. If there is another standard that addresses “secondary” Control Centers, the Purpose of IRO-002-5 should reflect that it only applies to a primary Control Center. If IRO-002-5 is left with “primary”, then primary Control Center will need to be defined in the NERC Glossary.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

<p>Texas RE appreciates the Standard Drafting Team’s efforts to develop a workable approach to requiring redundant and diversely routed data exchange infrastructure. However, Texas RE is concerned that the SDT’s proposed approach limiting such diverse routing requirements solely to primary control centers is overly narrow. Texas RE requests that the SDT apply the diverse routing requirements at issue here to control centers generally, rather than to just the primary control center. However, if the SDT declines to do so, Texas RE requests that the SDT clarify the relationship between TOP-001-4 and IRO-002-5 with the backup functionality requirements set forth in EOP-008. </p><p>In Order No. 693, FERC made clear that entities should possess backup capabilities that, among other things, “provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.” (p. 160, ¶335). In Order No. 817, FERC further identified a clear “reliability need for the reliability coordinator, transmission operator, and balancing authority to have data exchange capabilities that are redundant and diversely routed.” (p. 33, ¶47). Given the clear directive that entities possess backup control centers that can replicate the reliability functions of the primary control center, it seems contrary to the general ERO-wide approach to backup functionality to only require diverse routing within primary control centers.</p><p>This also appears counter to FERC’s specific discussion of the relationship between the general backup functionality requirements in EOP-008 and the more specific requirements for voice communications in the COM Standards and the data exchange capability standards at issue here. Specifically, in Order No. 817, FERC made clear that the EOP-008 redundancy requirements should not supplant the diverse routing obligations to be set forth in the revised TOP and IRO compliance obligations. That is to say, although it is possible to read the EOP-008 backup functionality requirements as mandating sufficient redundancy in and of itself, FERC

nevertheless called for the diverse routing reliability need to be explicitly addressed in the TOP/IRO Standards in the same manner as voice communications were addressed under the COM Standards. However, FERC’s directive does not appear to contemplate simply eliminating the diverse routing requirements from the TOP/IRO Standards (and arguably to EOP-008 Standard as well) altogether.</p>	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
See comments to question #2	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
What does the SDT consider “data exchange infrastructure”? Without an understanding of the intent of this language, it is unclear where the expectation for “redundant and diversely routed” ends. If the intent is to require the same level of demonstration of evidence as was provided under the old COM-001-1, then redundancy typically only had to be demonstrated by showing the two separate telecomm lines going to two separate routers and then from there it went into the single firewall and then into the ESP. If the ‘primary Control Center’ is considered within the single firewall/ESP boundary, then that should be clarified further in the requirement. Suggested changes to R2: R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure after the point the data enters the Transmission Operator's primary 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. We also would like to see the 90 day requirement to test changed to ‘Quarterly’. We have potential concerns (related to ‘where’ the boundary is considered for the Control Center) about which components need to be tested and what is considered an adequate test. Without knowing what components are included we may not test the right things.	

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

(1) We thank the SDT for responding to our request to clarify that testing of data exchange capabilities should only apply to the primary Control Center and at a required frequency greater than monthly.

(2) We believe the proposed requirements should follow a more performance-based approach and utilize the associated VSLs to identify the severity of non-compliance. In its current form, a registered entity could instantly become non-compliant if these data exchange capabilities or associated analytical tools become unavailable. We recommend that R1 be reworded to state “Each RC shall maintain data exchange capabilities with its BAs, its TOPs, and other entities it deems necessary, to perform its Operational Planning Analyses.”

(3) Likewise, we recommend that R2 be reworded to state “Each RC shall maintain data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the RC’s primary Control Center, for the exchange of Real-time data with its BAs, its TOPs, and with other entities it deems necessary, to perform its Real-time monitoring and Real-time Assessments.”

(4) We believe compliance should be embedded within existing business processes to better adopt such practices within a registered entity’s operations. Many registered entities already execute or follow the execution of quarterly processes, and we believe the testing of data exchange capabilities could be included in such processes like quarterly model updates. The tracking of every 90 days could be cumbersome for registered entities to coordinate test schedules and staffing levels for adequate test participation in advance. Moreover, it may be possible that two tests are conducted within the same quarter, something the SDT is likely trying to avoid, and could fall during operating periods that are of high risk to the BES. We recommend the periodicity of these tests, as identified in R3, be changed to calendar quarters.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

Please see comments in response to Question #5.

Likes 0	
Dislikes 0	

Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
While Clark is not an RC, it believes its arguments expressed in question 2 below are also applicable to the RC and that any similar requirements and measures applicable to the RC in IRO-002-5 should be similarly modified.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
We agree with the proposed changes but have a suggestion for a minor revision to the language of R1. It's very hard to enforce a standard that requires the Entity to "have" data exchange capability. While we don't need to require a formal procedure document, it should be clear that to comply with the standard, the Entity will be required to provide documented evidence as set out in M1. This comment also applies to R2. Suggested change: delete the word have and replace with document and implement **R1.** Each Reliability Coordinator shall ***have document and implement*** data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning].*	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

R4: Is the intent of the requirement to give System Operators the authority to *deny* planned outages and maintenance of telecommunication, monitoring and analysis capabilities, in the *Real-Time Operations and Same-Day Horizons*? It is hard to see the benefit of having shift System Operators in on the approval process of planned work of this type versus dedicated support staff that can evaluate this type of work and approve or deny the work during *the Operations Planning Time Horizon*; must System Operators be involved in the approval of this type of work in the *Operations Planning Time Horizon*? The requirement is difficult to understand since 'approve' is used instead of 'deny,' and three Time Horizons are listed as applicable.

R6: The phrase 'giving particular emphasis to alarm management and awareness systems…' is vague, ambiguous, and un-measurable, and makes interpretation of the standard difficult. This type of language has historically been eliminated from several standards under the Paragraph 81 criteria.

Are redundant *functionality* mentioned in R3 and redundant *infrastructure* mentioned in R6 two different things? Neither are defined terms and make interpretation of this standard more difficult.

Likes 0	
Dislikes 0	
Response	
Michael Puscas - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - 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; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	DTE Energy - Detroit Edison Company, 3, Barczak Karie
Dislikes 0	
Response	

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

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - 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; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 4	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Lyons - Owensboro Municipal Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	
Document Name	IRO-002-5 SOCO Comments.docx
Comment	

GSOC supports Southern Company's comments.

Questions

Do you agree with the changes made by the SDT to draft standard IRO-002-5? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

No

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

Comments: Southern believes that the language in IRO-002-5 R2 explicitly limits the scope of the requirement to “the data exchange infrastructure inside the Primary Control Center”. The first problem here is that the term “data exchange infrastructure” has no clear or broadly accepted industry definition.

The second problem is that here is no clear definition of what constitutes the control center. Is it a facility or a room inside a facility? What prevents someone from moving the “capability” outside the control center (i.e a data center not part of the control center)?

The language in IRO-002-5 R3 currently has a requirement to test the “primary control center data exchange capabilities” specified in R2” every 90 days. First of all, the terminology shifts from the word “infrastructure” in R2 to “capabilities” in R3, which leaves a lot of ambiguity. Why establish a requirement to test the redundancy of the data exchange and not the EMS platform in which the capability resides. This is perplexing given the fact that the data exchange function is, in most cases, a sub-component of the much larger distributed EMS architecture.

The language in IRO-002-5 R6 is also confusing, as it states that “each RC shall have monitoring systems that provide information utilized by the RC’s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. Again, this is very confusing, because the following questions have not been answered:

- What is meant by “particular emphasis”?
- Which “awareness systems” require redundant infrastructure
- Which “automated data transfers” are in scope?
- Which “synchronized information” is in scope?
- What level of redundancy is required? Server level, component level, network level, etc.

Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
The comments provided by the NSRF that are applicable to TOP-001-4 are also applicable to IRO-002-5 for similar requirements.	
Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	

Comment

1. **Abstain** (standard is not applicable to HONI)

Likes 0	
Dislikes 0	

Response

2. Do you agree with the changes made by the SDT to draft standard TOP-001-4? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

Thomas Lyons - Owensboro Municipal Utilities - 3	
Answer	No
Document Name	
Comment	

. Documented assessments every 30 minutes is an unnecessary administrative burden.

Likes 0	
Dislikes 0	
Response	

Douglas Webb - 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; - Douglas Webb	
Answer	No
Document Name	
Comment	

No.

The SDT revisions to the R10 Rational do not address the double criteria application created by the proposed revisions to Requirement 10.

The SDT, in response to TOP-001-4 R10 Draft 1 comments, writes, “The SDT does not agree that the proposed changes to R10 affect the applicability of facilities within the CIP-002-5.1 standards.”

Without understanding how the SDT came to their position, we have to respectfully disagree with the SDT’s assessment.

The issue is not R10 affecting the applicability of facilities within CIP-002-5.1; the issue is R10 may create compliance obligations under CIP-002-5.1.

When a non vBESdFacility can adversely our term for purposes of these comments). The STD’s comments confirm this view, writing, “The SDT agrees that analyses performed in support of BES inclusions can identify some non-BES facilities that should be monitored for reliability…“

The Converted non -BES Facility is treated as a B -2.2, “All BES Facilities.”

As a BES Facility, Entities are required to evaluate the Facility under CIP-002 to determine whether it is a High, Medium, or Low Impact BES Cyber System.

Our Concern

Bringing the BES Facility into CIP -002-5.1 Low Impact creates a double applicability criteria situation.

In other words, not identifying the non-BES Facility as potentially impacting the BES under R10—a compliance failure—automatically creates another compliance failure under CIP-002-5.1 because all BES Facilities are to be categorized and, as required, protected.

Put another way, in the event a non-BES Facility impacting the BES is not identified under R10 and should have been—it was missed—the Entity would be hard-pressed to justify that CIP-002-5.1 only applies to the non-BES Facilities identified under R10 and not to the "missed" Facilities. It would have to be a common sense justification but from a real-world view, the proposition is difficult to defend.

The current Proposed Standard creates the situation that a compliance failure with R10 creates a compliance failure under CIP-002-5.1.

Suggestion to Address the Issue

We do not believe this is an instance when the issue can be addressed by a single SDT; it requires the CIP Modifications SDT and potentially others, current and the future, to consider how revisions align with other Standards and the potential for a double impact criteria situation.

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Please see comments in response to Question #5.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

For R9, the focus on this comment is based on how this relates to EMS, SCADA and associated control systems. WAPA would contend that switching to a redundant host (server, system, computer, etc) that provides functionally equivalent service, that this would not fall under the banner of a "planned outage". If an entity were to not have functionally equivalent redundant hosts and perform a switch-over, this would fall under the planned or unplanned outage banner. WAPA would like to get clarification on this as to plan appropriately for its process to meet the new standard verbiage.

For R20, The verbiage that was changed in the rationale raises concerns as it relates to how this will be audited. Data Exhcange Infrastructure is used in both the Rationale, the Requirement, and the Measure. Yet the Rationalse provides signinficantly more detail and yet at the same time a wider scope. The concern is focused on the items listed in the Rationale:

(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)

The first example of concern with this verbiage is that the Requirement and the Standard focuses on "*redundant and diversely routed data exchange infrastrcuture*" but the Rationale seems to expand the scope of this to focus on components of devices instead of the devices themselves. To draw a logical leap, would an entity be expected to have devices with redundant power supplies or is redundant power into the control center sufficient. WAPA would like to see the Rationale match the Standard and Measure verbiage. The other seemingly untouched area is the discussion around technology that make redundant paths much less effective or possibly not needed at all. If, for example, a group of entities were to have a cloud technology (lets use MPLS for example) infrastructure that provides redundancy; would this meet the letter of the law even though redundancy at a device level may not exist? This may not necessarily meet compliances as described but provides the level redundancy that the standard is striving for. WAPA feels the focus on redundant and diverse links may cause the industry to miss the wider use of many technogologies available to us because we would be focused on meeting compliance rather than engineering a reliable and effective solution.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

(1) We thank the SDT for responding to our request to clarify that testing of data exchange capabilities should only apply to the primary Control Center and at a required frequency greater than monthly.

(2) We caution the SDT in its phrasing of language used to address a FERC directive requiring TOPs to monitor non-BES facilities, as deemed necessary by the TOPs, to fill their functional obligations. Rather than dive into a philosophical discussion regarding States rights versus the jurisdiction of FERC, we focus our concerns on the practical application of this language. Many of the non-BES facilities are owned and maintained by entities not listed within the NERC compliance registry. Some of these non-registered entities were de-registered following the approval of the Risk-based Registration initiative. Moreover, owners of non-BES facilities outside a TOP Area may not have direct business ties or incentives to coordinate with the TOPs. We recommend removing non-BES facility references from these standards, or as an alternative, rephrasing the appropriate parts of R10 to monitor and obtain statuses, voltages, and flow data for non-BES facilities, when such information is available.

(3) Moreover, we continue to have concerns that the proposed additional requirements require a registered entity to possess data exchange capabilities and not maintain such capabilities. By focusing on possession, a registered entity could instantly become non-compliant if these data exchange capabilities or associated analytical tools become unavailable. We believe the requirements should follow a more performance-based approach and utilize the associated VSLs to identify the severity of non-compliance. For instance, we propose rewording Requirement R19 to "Each TOP shall maintain data exchange capabilities with entities it deems necessary to perform its Operational Planning Analyses." This proposal could be reused to modify the similar BA requirement, R22.

(4) Likewise, we propose rewording Requirement R20 to "Each Transmission Operator shall maintain data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, needed to perform Real-time monitoring and Real-time Assessments." This proposal could be reused to modify the similar BA requirement, R23.

(5) We feel compliance should be embedded within existing business processes to better adopt such practices within a registered entity's operations. Many registered entities already execute or follow the execution of quarterly processes, and we believe the testing of data exchange capabilities could be included in such processes like quarterly model updates. The tracking of every 90 days could be cumbersome for registered entities to coordinate test schedules and staffing levels for adequate test participation in advance. Moreover, it may be possible that two tests are conducted within the same quarter, something the SDT is likely trying to avoid, and could fall during operating periods that are of high risk to the BES. We recommend the periodicity of these tests, as identified in R21 and R24, be changed to calendar quarters

(6) We believe the use of the NERC-defined Glossary Term, Operating Plan, is incorrectly applied in Requirement R22. To paraphrase, an Operating Plan is a group of activities, Operating Procedures, or Operating Processes that are used to achieve a goal. In the case of this requirement, what is the goal a BA assessing its next-day operations trying to achieve? We recommend avoid using the NERC glossary term in this context or use a NERC defined term like "Adequacy."

(7) In light of the removal of operating logs as evidence identified within Measures M20 and M23, we ask the SDT to reflect this removal in the Evidence Retention Section of this standard (i.e. Section C.1.2).

Likes 0	
Dislikes 0	

Response

Chris Gowder - 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; - Chris Gowder, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA believes the meaning of redundant and diversely routed remains unclear, and that entities (and auditors) would benefit from having some examples of configurations that meet the expectations. Does a failover configuration where there is a potential for multiple combinations of active (or live) components meet the redundancy and diversely routed requirement, or does it require a completely separate set of isolated components from top to bottom? For example, a primary server could be setup to be capable of using either a primary and secondary switch. The secondary server would be setup the same way, so at any given time a combination of primary and secondary devices could be active. The boundary of what is considered within the Control Center is also unclear.

Entities are currently having to decipher what is required or proposed to be required by the CIP standards, which involve the very same equipment being discussed here. It is vital that the various Subject Matter Experts involved in the two efforts speak the same language and have a common understanding of what is meant by words such as "failure or malfunction" and "redundant and diversely routed". We believe there is too much room for interpretation as the Requirements are currently worded.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

We would like to see some changes in the Rationale for R10 to clarify that the intent is to monitor the non-BES facilities 'so that a TOP can determine SOL exceedances' not just monitor non-BES facilities. We think clarifying also that the reliability impact to be guarded against is impact on the BES, not on the non-BES facilities. Please make the following change: The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact BES reliability are monitored.

A similar change would also be helpful in the following sentence:

The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances on BES Facilities within its Transmission Operator Area.

What does the SDT consider "data exchange infrastructure"? Without an understanding of the intent of this language, it is unclear where the expectation for "redundant and diversely routed" ends. If the intent is to require the same level of demonstration of evidence as was provided under the old COM-001-1, then redundancy typically only had to be demonstrated by showing the two separate telecomm lines going to two separate routers and then from there it went into the single firewall and then into the ESP. If the 'primary Control Center' is considered within the single firewall/ESP boundary, then that should be clarified further in the requirement.

Suggested changes to R2:

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure after the point the data enters the Transmission Operator's primary 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.

We also would like to see the 90 day requirement to test changed to 'Quarterly'.

We have potential concerns (related to 'where' the boundary is considered for the Control Center) about which components need to be tested and what is considered an adequate test. Without knowing what components are included we may not test the right things.

Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	

We agree with the overall objective of the proposed revisions to the standard to ensure accurate system modeling for Real-time Assessment and real-time monitoring along with driving towards reducing the impacts to those processes of single points of failure for data systems. However, the proposed verbiage changes from the previously balloted standard concerning testing frequency in R21 and R24 does not go far enough to differentiate between situations where redundant internal data exchange capability is provided in an active-active configuration versus an active-standby configuration. In an active-active configuration the redundant internal data exchange capability is being tested through the ongoing use and monitoring of the equipment providing the redundant capability. In an active-standby configuration the equipment providing the redundant internal data exchange capability is not being continually tested and warrants an explicit testing requirement. The quarterly testing requirement for an active-standby configuration is appropriate. In an active –active configuration no dedicated testing is necessary at any scheduled intervals since equipment is continually being tested through use and monitoring. This approach encourages an active-active configuration which clearly provides enhanced reliability since there are no potential gaps where redundant capability is lost and not recognized until the next test.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

<p>Please see Texas RE’s response to the #1 regarding the specificity of primary control centers. The same concerns apply to IRO-002-5.</p><p> </p><p>Texas RE noticed TOP-001-4 Requirements R19 and R22 do not specify “data exchange capabilities, with redundant and diversely routed data exchange infrastructure”. Requirements R20 and R23 do specify “data exchange capabilities, with redundant and diversely routed data exchange infrastructure”. Is it the SDT’s intent that the data TOPs and BAs use to develop an Operations Planning Analysis not be redundant and diversely routed?</p>

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no National Grid

Answer	No
Document Name	

Comment

TOP-001-4 Requirement R10 is redundant with IRO-002-5requirmeent R5. Both refer to the moinitoring of facilities. The revisions to the Rationale for Requirement R10 reinforce this.

Likes 0	
Dislikes 0	

Response

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	

Requirement R20:

NSRF revisions add further clarity to redundant and diversely routed within the Requirement. It's important to maintain a balance between being specific and overly prescriptive in a mandatory zero-defect environment. We suggest the following revision allows entities to clearly define two primary control center data paths and the flexibility to identify what needs to be redundant while meeting FERC's objectives. Allowing entities to define two data infrastructure paths also recognizes that auditing to all possible single points of failure isn't realistic or feasible.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant (meaning at least two data exchange paths exist for normal operating conditions) and diversely routed data exchange infrastructure (meaning switches, routers, file servers, power supplies, and network cabling in communication paths between these components in the two identified data exchange paths) within the Transmission Operator's primary 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. The planned or unplanned loss of one of the two data exchange infrastructure paths does not require further actions to meet compliance.

Requirement R23:

The following suggested revisions makes R23 consistent with the revisions suggested for R20.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure (meaning switches, routers, file servers, power supplies, and network cabling in communication paths between these components in the two identified data exchange paths) within the Balancing Authority's primary Control Center, 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 analysis functions.

Suggestion for R21 and R24:

The NSRF thanks the drafting team for changing the periodicity for testing data exchange capabilities from the previous monthly periodicity. NSRF recommends changing the revised 90-day testing periodicity to **quarterly**. While the industry appreciates standardization, there is a benefit to changing 90 days to **quarterly**. This avoids continually accelerated tracking and rotating compliance periods. Operationally, moving to the largest testing period to maintain adequate reliability allows personnel flexibility in scheduling, tracking, and completing work. Quarterly is superior to 90-days, Bi-annual is superior to 6-months, and annual is best unless a specific reliability need is identified.

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

TOP-001-4 R20 - Please see comments regarding data exchange capabilities noted in Question #1.	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	FERC Order.jpg
Comment	

ATC is concerned regarding requirement 10.3 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 our 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 oeprating parameters, whether impedances, charging values or ratings, or we do not have the correct telemetry, we cannot monitor their facilities (e.g., confirm flows are within limits). 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 they are not required to provide it monitoring is not feasible and thus not required.

Requirement 20 was modified to indicate the need for redundant and diversely routed data exchange capabilities within the TOPs primary control center. The way the standard is written ignores the enhanced redundancy ATC has implemented between control centers such that we can survive the loss of a single control center. I believe it is contrary to the intent of the commission order (see below) which requires that "the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing". I would recommend that the SDT modify the wording to allow for TOPs or BAs that have implemented redundancy across multiple primary control centers.

Requirement 21 was modified such that data exchange capabilities used in the primary Control Center have to be tested once every 90 days. The SDT did extend that from every 30 days which was a positive result of the first round of comments. Since ATC's redundancy is built into the overall system architecture, where the loss of an entire control center can be withstood, verifying capabilities within one or both of our centers is above and beyond the intent of the FERC order (attached).

ATC agrees with the following comments put forth by NERC Stansdards Review Forum (NSRF).

Suggestions for Requirements R20 and R23:

The term ‘redundant and diversely’ routed is undefined and ambiguous. NSRF suggests the following wording change for these two requirements: “Each Balancing Authority (TOP) shall have data exchange capabilities, with redundant and diversely routed that reduce or mitigate single points of failure of data exchange infrastructure within the Balancing Authority's(TOP) primary Control Center in the exchange of identified Real-time data” . The NSRF believes that this suggested language can also be applied to other Entities that require a reduction of single points of failure.

Suggestions for R21 and R24:

The NSRF thanks the drafting team for changing the periodicity for testing data exchange capabilities from the previous monthly periodicity. Within the comments to the first round of comments the drafting team indicated that they had moved the periodicity to quarterly, but actually put in 90 days. This may sound like a small thing, but from a compliance standpoint tracking 90 day periodicity versus a quarter periodicity can be a big thing. If an entity tracks by a quarter and completes their testing on a 91st day of a 91 day quarter, they are out of compliance. In addition, our technicians that test would find it less of a compliance burden to track quarter testing than tracking 90 day intervals. We would suggest that the wording in these two requirements actually use the term “quarter” or “quarterly”.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

R16, R17: See our comment regarding R4 of IRO-002-5 above.

R20-R24: Redundant infrastructure and redundant functionality terms are again used in different requirements. An entity can have redundant functionality without redundant infrastructure. For example, you can have a single router/switch/piece of network equipment with redundant paths/functionality, but if power to the switch is lost then the functionality is lost because you don’t have redundant infrastructure.

R21: It is not clear what is required to test redundant functionality. This could include each piece of network infrastructure inside the primary control center (ICCP boxes, routers, switches, EMS computers, System Operator computer consoles, etc.) If this is left vague then it is not a good fit for a standard, but should be considered a guideline.

R21-24: We request further clarification/explanation from the drafting team on the extent of the testing addressed in R21. Is it the drafting team’s intent to require an entity to test an entire pathway for redundant functionality every 90 calendar days, or is testing required on single elements only? The language in the requirement does not specifically address the extent of the testing expected. We recommend that language clearly outlining the extent of testing necessary to achieve compliance necessary be inserted in the requirement(s) or perhaps further explanantion in the rationale.

Also, Duke Energy is unsure that the proposed requirements R20-R24, do not fit with the overall purpose of the TOP standard family. The purpose outlined in TOP-001-4 states:

“To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.”

We do not believe that the required actions in R20-R21 and R23-R24 are placed appropriately in this standard. We are in agreement that some of the actions may be deemed necessary, however, we are not convinced that said actions would prevent instability, uncontrolled separation, or Cascading

outages that may adversely impact reliability of an Interconnection. Duke Energy suggests the drafting team consider another standard, perhaps TOP-003-3, for the directed requirements. TOP-003-3 aligns better with these new requirements instead of being placed in TOP-001-4 and suggest moving R19 and R22 from TOP-001-4 to TOP-003-3 also (these requirements are currently R19 and R20 in TOP-001-3).	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
NVE still has concerns with the identification of non-BES facilities. The proposed TOP-001-4 RSAW requires the Transmission Operator to provide evidence that it monitored all the data for non-elements identified, but no guidance on evidence to show that we do or do not have non-BES facilities. Would we need to provide studies to show that we have no non-BES facilities? We also have concerns about how non-BES facilities outside the Transmission Operators Area should be identified by the TOP. Some sort of methodology or guidance should be added to the Requirement to demonstrate the identification of non-BES facilities.	
Likes 0	
Dislikes 0	
Response	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	No
Document Name	
Comment	
R10.4, R10.5, & R10.6 duplicate the requirements in the already approved TOP-003-3, R1. R19 & R20 overlap with the requirements in the already approved TOP-003-3, R5.	
Likes 0	
Dislikes 0	
Response	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller	

Answer	No
Document Name	
Comment	

Comments: See comments below.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

R10. In the previous version of TOP-001-4, R10 required TOPs to monitor non-BES facilities necessary for determining SOL exceedances both within and outside its footprint “identified as necessary by the TOP.” This has been broadened to include the RC with the introduction of new text in the “Rationale for Requirement R10” box; which states that any of the following could lead to an identification of non-BES facilities that should be monitored:

1. APS OPA
2. APS RTA
3. APS analysis to determine BES Inclusion Exceptions
4. Peak RC analysis performed in support of outage coordination (requiring temporary monitoring)

This is problematic for several reasons:

1. The RC model may not be as robust as the TOP’s model for non-BES facilities. Therefore, the RC’s ability to determine which non-BES facilities affect the BES is limited without TOP input. A "vetting" process should be added whereby the RC must validate the non-BES facilities to be added with the TOP.
2. Temporary monitoring of non-BES facilities, if the IT infrastructure is not already in place, may not be feasible depending on the lead time available in the RC’s outage coordination process; particularly if the facilities are not already modeled and/or the data is not readily available. For example, in the Western Interconnection, Peak Reliability initiates their OPA studies only two days before the scheduled outage.

At a minimum, if support of the RC outage coordination process is to remain as part of requirement R10, then the text of the requirement should be expanded to specifically include the RC: “**identified as necessary by the TOP or by the RC in support of their outage coordination process**.”

R20 and R23. The introduction of the word “primary” as a clarifier to Control Center is problematic in that it limits where the an entity may locate its “redundant and diversely routed data exchange infrastructure” to that within the “primary Control Center.” As APS has redundant and diversely routed data exchange infrastructure *across* (and not *within*) Control Centers; i.e. infrastructure that spans our primary and back-up Control Center locations, the requirement as written limits flexibility in terms of where redundant infrastructure may be located. As worded, this would require entities to install additional redundancy within its primary Control Center location.

If the SDT’s intent is to ensure the reliability of data exchange structure used to maintain its data exchange operations within the primary control Center, we propose modifying the language as follows to recognize redundant data exchange capability infrastructure across an entity’s *collective* Control Center facilities:

APS Proposed R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure **used to maintain its operations** within the Transmission Operator's primary 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.

APS Proposed R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure **used to maintain its operations** within the Balancing Authority's primary Control Center, 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 analysis functions.

Likes 0	
Dislikes 0	

Response

Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith

Answer	No
Document Name	

Comment

Oncor's comments have no change from the last draft as there is no change to the Standard Requirement in this draft. Revisions made in rationale boxes do not change the requirement and often are removed when the Standard becomes effective.

*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	

Response

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
For Requirement R10.6 we are concerned how non-BES facilities outside the Transmission Operator Area should be identified by the TOP? We believe that this should be specified. This is partly mentioned in the Rationale for Requirement 10; but is not part of this requirement. The requirement should be set up to complement the other standards' requirements.	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	
Comment	

R20 Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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.

{C}1.   {C}This requires redundancy and diverse routing only within the Transmission Operator's primary control center. The communication links referenced could easily cover hundreds of miles, and they can only be well protected during the last few hundred feet within an entities facilities. This requirement says you must have redundancy and diversity for the short and well controlled portion, but not for the much longer, less controlled, and thus more vulnerable portion. I cannot see a technical basis for this approach.

{C}2.   {C}The term "diversely routed" as applied to the area within a Control Center is not well defined. For example, can the two cables be within the same cable tray for a short distance? If so, for how long?

{C}3.   {C}The extent of redundancy required is not clear. Would this require redundancy in the servers that are the source of the data, would it require redundant Ethernet ports on such a server, would it require redundancy in the power supplies supporting the equipment? All these questions (and more) must be answered for an entity to design a compliant solution.

{C}4.   {C}Has any work been done to determine how frequently a failure within a control center is the cause of a data communications failure? It would seem necessary to do something like that before implementing this requirement.

{C}5.   {C}The rationale implies that failure to have redundant facilities in place when one set of facilities is being upgraded is not a violation of the requirement, but there is nothing in the actual requirement to support that. That is not an appropriate use of the rationale section. Consider adding the following at the beginning of the requirement: "Except during planned outages of less than two weeks duration and during unplanned outages, . . . "

{C}6.	{C}This requirement is focused on infrastructure. It is not clear how the availability of a completely different approach to the data exchange might meet this requirement. If the data set was small enough that it could be verbally exchanged via telephone, faxed, emailed, or FTP'd to the other party, would that meet the requirement? Consider rewording the requirement to state the objective more broadly and therefore allow these approaches to be used to meet compliance.

{C}7.	{C}The requirement does not take into account variability in the criticality of the data. Where failure of a data link to one entity might be a minor annoyance, failure of a link to another might be catastrophic. This requirement allows no flexibility in matching the degree of redundancy and diversity to the associated risk of the loss of the data. Consider giving the TOP latitude to determine the appropriate level of redundancy for a particular link, particularly in consideration of the criticality of the data and the reliability of various parts of the data exchange infrastructure.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

1.	The second sentence in the second paragraph should not be part of the rationale of the standard. The rationale should include the reasoning behind the standard. This statement attempts to add an element to the requirement and thus should be part of the requirement. As it stands now it will introduce confusion over whether incorporating various failure modes is mandatory or advisory.

2.	Similarly the third sentence in the second paragraph should not be part of the rationale of the standard. If an actual event can be substituted for a test, that should be made part of the requirement as it is done in other standards. See CIP-009, R2 for an example of how this can be accomplished correctly.

Likes 0	
Dislikes 0	

Response

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Requirement 20 defines the needs for "data exchange infrastructure". SRP feels that this is prescribing a technology solution for the need for redundant and diversly routed data exchange capabilites that is implied. Entities must be responsbile for determining the method for obtaining compliance. The standards need to refrain from defining a solution that may be difficult to obtain for all entities.

Likes 0	

Dislikes 0	
Response	
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. The Time Horizon for R10 is "Real-Time Operations", and while the monitoring of non-BES facilities may be accomplished in Real-Time, their identification *cannot* be. Some sort of methodology or guidance should be provided for the monitoring of non-BES facilities and the associated data, specifically data from outside the Transmission Operator's area. As previously stated, rather than developing additional requirements which would not likely be beneficial, we continue to believe a more prudent approach is to focus on the desired end state itself. We still believe the argument can still be made that our existing obligations, when considered as a whole, could collectively appease FERC's concerns.

While we appreciate the SDT's recent revisions which no longer requires monthly testing, we once again recommend using the text "once a calendar quarter" rather than "every 90 calendar days" as is most recently proposed.

Likes 0	
Dislikes 0	
Response	
Joe Tarantino - 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; - Joe Tarantino	
Answer	No
Document Name	
Comment	

We appreciate the work that the Drafting Team has provided specific to the TOP-001-4 Reliability Standard. However, our concern remains over the test language found in Requirements R21 for the TOP and R24 for the BA. While we understand that monitoring functions do not constitute sufficiency in testing we are concerned that the "test" terminology is subject to interpretation by the responsible entity, auditor, and others that lend itself to inconsistent implementation/auditing of these requirements. To resolve this reliability concern, please clarify the drafting team's intent for the "test" requirement whether this is explicit to each data link or the data link infrastructure or some other intention. We, Sacramento Municipal Utility District and Balancing Authority Northern California, look forward to a resolution from the drafting team on this issue… Thanks.

Likes 0	
Dislikes 0	

Response

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

Comment

Clark believes that R20 is still not addressing the issue FERC has expressed its concern over. Please read the paragraph in question. In Paragraph 47, Order 817, FERC states:

"We agree with NERC and other commenters that there is a reliability need for the **reliability coordinator, transmission operator and balancing authority to have data exchange capabilities that are redundant and diversely routed**. However, we are concerned that the TOP and IRO Standards do not clearly address redundancy and diverse routing so that **registered entities will unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations**. NERC's comprehensive approach to establishing communications capabilities necessary to maintain reliability in the COM standards is applicable to data exchange capabilities at issue here. Therefore, pursuant to section 215(d)(5) of the FPA, **we direct NERC to modify Reliability Standards TOP-001- 3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing.** In addition, we direct NERC to clarify that "redundant infrastructure" for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities."

The SDT continues to **INCORRECTLY** apply this paragraph first to control centers and now to primary control centers. Paragraph 47 is applicable to the registered the entities RCs, TOPs, and BAs and requires these registered entities to have the referenced redundancy and diverse routing of data exchange. **The terms "control center" or "primary control center" are not used in Paragraph 47**. The SDT continues to fail to recognize that many RCs, TOPs, and BAs already have redundancy and diverse routing of data exchange that addresses the FERC's concerns because they have voluntarily adopted this approach in meeting their COM standards compliance and their EOP-008 compliance.

In Paragraph 48, Order 817, FERC states:

"Further, **we disagree with commenter arguments that Reliability Standard EOP-008-1 provides alternatives to data exchange redundancy and diverse routing**. The NERC standard drafting team that developed the COM standards addressed this issue in the standards development process, responding to a commenter seeking clarification on the relationship between communication capabilities, alternative communication capabilities, primary control center functionality and backup control center functionality. The standard drafting team responded that "Interpersonal Communication and Alternative Interpersonal Communication are not related to EOP-008," even though Reliability Standard EOP-008-1 Requirement R1 applies equally to data communications and voice communications. To the extent the standard drafting team asserted that Reliability Standard EOP-008 did not supplant the redundancy requirements of the COM Reliability Standards, we believe the same is true for data communications. Redundancy for data communications is no less important than the redundancy explicitly required in the COM standards for voice communications."

In Paragraph 48 the FERC **DID NOT state that the use of a backup dispatch center in the provision of alternatives to data exchange redundancy and diverse routing fails to address its concerns expressed in Paragraph 47** . It only stated that the requirement to have such data exchange redundancy and diverse routing is not specifically provided for in EOP-008-1. There is no reason for the SDT to believe that the requirements of Paragraph 47 should be applied to the primary control center. There is every reason to believe that the requirements of Paragraph 47 should be applied to the RCs, TOPs, and BAs provision of reliability data using data exchange capabilities that are redundant and diversely routed.

As such the SDT needs to modify R20 and M20 to the following:

"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. [Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]"

"M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including 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 to perform its Real-time monitoring and Real-time Assessments as specified in the requirement."

The above revisions to R20 and M20 will cause Transmission Operators to **"unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations"** which is the concern FERC has expressed. These changes will allow TOPs to submit evidence that the redundant and diversely routed data exchange capabilities being voluntarily used in compliance with the COM standards and EOP-008-1 are also capable of meeting the new MANDATORY requirements of TOP-001-4. The SDT should have no concern that the FERC would reject this since Paragraph 47 clearly **DOES NOT REQUIRE THIS REDUNDANCY AND DIVERSE ROUTING OF DATA EXCHANGE FOR PRIMARY CONTROL CENTERS BUT ONLY FOR RCs, TOPs, and BAs as registered entities.**

While Clark is not an RC or a BA, it believes the above arguments are also applicable to these registered entities and that any similar requirements and measures applicable to these entities in IRO-002-5 or TOP-001-4 should be similarly modified.

Likes 0	
Dislikes 0	

Response

Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

R10.3 states that the TOp must monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator. In the latest revision of the standard, the Standard Drafting Team added language to the Rationale section of the draft standard to clarify that the non-BES facilties that the TOp is required to monitor are "only those that are necessary for the TOp to determine SOL exceedances within its Transmissoin Operator Area." While TVA appreciates the additional details in the Rationale section, we feel that the additional details around identification of non-BES facilities belongs in the requirement itself. Compliance obligations are now spreading down below 100 kV facilities into the non-BES system. Whereas there use to be a hard line between where the compliance purview began and stopped, it will now be at times, more ambiguous. For example, now non-BES facilities can be labeled BES facilities or, if this standard passes as written, non-BES facilities will still be non-BES but be required to be monitored if the TOp decides as such. We would prefer to see more clarity in the requirement as to when the TOp would require a non-BES element be monitored. TVA suggests the following language change for the requirement:

“R10.3 Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator **in order to determine SOL exceedances on BES elements whithin its Transmission Operator Area.**”

Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
New requirement R20 requires TOPs to have “redundant and diversely routed data exchange infrastructure **within** the Transmission Operator’s primary Control Center.” R23 contains a similar requirement for BAs to have similar infrastructure “**within** the Balancing Authority’s primary Control Center. It has been the ISO’s understanding that the concern was with redundancy **into and out** of the Control Center, to and from the outside world. However, the terminology “**within the control center**” could be construed differently that there is some expectation of diversity and redundancy before the data leaves the control center. The ISO requests that the Drafting Team clarify whether or not the intent of this terminology is to apply to routing after the data leaves the Control Center. If indeed the new requirement is meant to apply within the Control Center, the ISO requests that more specificity be provided as to what the expectation is for redundancy and diversity (i.e. - Between one operator and another? Between an operator computer and or phone, and the data exchange infrastructure itself?)	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Puscas - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

3. 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.

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

If requirement R10 allows the RC to stipulate non-BES facilities be monitored, 24 months should be allocated to install, test and implement the proper equipment.

In addition, if requirements R20 and R23 remain as they are currently worded, such that the TOP and/or BA are required to install redundant and diversely routed data exchange infrastructure within the primary Control Center (only), and do not allow for flexibility for the redundant and diversely routed data exchange infrastructure to span across Control Centers, then APS proposes a minimum of 3 calendar years for implementation.

Likes 0	
Dislikes 0	

Response

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller

Answer	No
Document Name	

Comment

Comments: See comments below.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

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 data identified in TOP-003-3 to monitor non-BES facilities. In that scenario, more time may be needed than what is proposed for Requirement 10.

Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy has concerns regarding the effort to achieve compliance with IRO-002-4, and the possible quick turnaround for becoming compliant with IRO-002-5. Entities have already made interpretations, and taken specific actions to achieve compliance with IRO-002-4 prior to it being enforceable in April of 2017. With the potential for such a quick turnaround in standard versions, we believe that delaying the enforcement date for IRO-002-4 until IRO-002-5 is approved and enforceable would be prudent. The delaying of enforcement dates to consolidate versions has happened in the past (see PRC-005). We believe that rolling all changes and enforcement dates to the potential enforcement date for IRO-002-5 is a practical solution for industry stakeholders in achieving compliance with the different versions.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Please see comments for Question #1.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

We need further guidance on which aspects of our data exchange capability should be redundant in order to answer this question. The old COM-001 was more focused on capabilities outside the Control Center (avoiding the 'backhoe' outages) while this requirement seems to be focused on redundancy within the data center, but ignoring redundancy outside the data center. Additional rigor may need to be added to internal redundancy. Based on that, the 12 month implementation plan may be insufficient. Redundancy and diverse routing in the legacy requirements seemed to mean something different than is being presented in the directive by FERC today.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

We thank the SDT for providing clarity that the scope of the requirements are aimed at the applicable entity's primary Control Center. However, we disagree with the SDT that entities will have sufficient time with a 12-month implementation plan. That assumption is based on TOPs and BAs already have adequate infrastructure and data exchange capabilities in place to perform their SOL exceedance determinations, monitoring, and assessment calculations. We believe there is a possibility that they won't, particularly with owners of non-BES facilities that are identified as necessary for TOPs and BAs to complete their functional obligations. In this instance, TOPs and BAs could be faced with a compliance-based decision to either sacrifice reliability concerns by identifying these facilities as not necessary for monitoring and assessments or identify, procure, install, and continue to maintain adequate infrastructure and data exchange capabilitibities with these facilities in order to remain compliant. In the latter instance, incurring such costs could be done outside budgeting approvals for smaller entities, particularly in a compressed 12-month implementation period. We propose a 24-month implementation period instead, as that could accommodate 2-3 possible budget cycles.

Likes 0	
Dislikes 0	

Response

Douglas Webb - 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; - Douglas Webb

Answer	No
Document Name	

Comment

No.

The proposed Implementation Plan does not consider the time required to meld the technology required to address compliance under TOP-001-4 R10 and compliance under CIP-002-5.1. The period should be extended by a year.

Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
No - TOP-001-4 No - IRO-002-5	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
: No concerns with the timelines proposed with implementation assumed 4/1/2018 based on current schedule.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
<p>Texas RE appreciates the SDT’s inclusion of an “Initial Performance of Periodic Requirements” section. Texas RE believes that this is a best practice and recommends that future SDTs provide a similar section for all periodic requirements to avoid ambiguity.</p><p>Texas RE does not necessarily object to the SDT’s proposed 12-month implementation period. However, Texas RE	

respectfully requests that the SDT provide a basis for its decision to adopt such a 12-month compliance window, including any data it considered in determining that this was an appropriate window for affected entities to meet their compliance obligations under the revised Standards. </p>	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Puscas - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - 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; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no National Grid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thomas Lyons - Owensboro Municipal Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. 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.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
(1) We thank the SDT for responding to our request to account for the "as necessary" parts of requirement R10 within the VSLs. (2) However, we believe the SDT has an opportunity to develop more performance-based requirements for these standards. We believe the VSLs for these requirements should base compliance on a definite period of time that has lapsed when a registered entity is unable to perform its monitoring functions or conduct its assessments. This scalable time duration could then be used to identify VSLs for the complete set, and not just values for Severe VSLs. We propose an exceedance of 30 minutes listed as a Low VSL, with a 30-minute increment for each increasing severity limit.	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
As proposed, the VRFs and VSLs treat each R10 sub requirement equally when in reality both the risk and resulting potential impact is significantly different between the requirements. The risk and associated potential impact of a TOP not monitoring it's own Facilities and RAS's is significantly greater on the ability for state estimation and contingency analysis to solve and provide accurate results than to not monitor non-BES facilities within it's system or external TOP areas' Facilities/RAS's/non-BES facilities.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Please see comments for Question #1.	
Likes 0	
Dislikes 0	
Response	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller	
Answer	No
Document Name	
Comment	
Comments: See comments below.	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - 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; - Joe Tarantino	
Answer	No
Document Name	
Comment	
We are concerned over the issue raised for "test" in TOP-001-4 Requirements R21 & R24 pertaining to the lack of clarity for implementation and audit approach and therefor cannot agree with and VRF/VSL associated with these requirements.	
Likes 0	
Dislikes 0	
Response	
Michael Puscas - ISO New England, Inc. - 2	
Answer	No
Document Name	

Comment	
The language for the NERC Standard, IRO-002-5, R3, Severe VSL. The last paragraph states: The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once each every 90 calendar month days but, following an unsuccessful test, did not initiate action to restore the redundant functionality in more than 8 hours. This does not convey the intent. Literally, it says that the violation occurred because the action was initiated in 8 hours or less or that there were 8 or fewer hours in which actions were initiated. I'd suggest changing the language to: **The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once each every 90 calendar month days but, following an unsuccessful test, did not initiate action to restore the redundant functionality within 8 hours of the test failure.**	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
They seem consistent based on the requirements as stated. If the periodicity changes to 'quarterly' the VRF's and VSL's would need to change accordingly	
Likes 0	
Dislikes 0	
Response	

Thomas Lyons - Owensboro Municipal Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - 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; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Beuthling - Mike Beuthling On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no National Grid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	
Document Name	
Comment	
No - TOP-001-4	

No - IRO-002-5	
Likes 0	
Dislikes 0	
Response	

5. Provide any additional comments for the SDT to consider, if desired.	
Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

Clark believes that R21 is still not addressing the issue FERC has expressed its concern over. Please read the paragraph in question. In Paragraph 51, Order 817, FERC states:

"We agree with NERC and other commenters that there is a reliability need for the reliability coordinator, transmission operator and balancing authority to test alternate data exchange capabilities. However, we are not persuaded by the commenters' assertions that the need to test is implied in the TOP and IRO Standards. Rather, we determine that testing of alternative data exchange capabilities is important to reliability and should not be left to what may or may not be implied in the standards. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to **develop a modification to the TOP and IRO standards that 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.** 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."

The only reference to the primary control center in Paragraph 51 is that the overall data exchange capabilities needs to be tested to ensure that "**the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority" are tested.** If the exchange capabilities used in the primary control centers are the **primary or most frequently used data exchange capabilities**, it is obvious that some other alternate data exchange is the scope of the FERC's directive. This may be and alternate data exchange capability in the primary control center but there is nothing in Paragraph 51 that would preclude the use of a backup control center for the provision of the alternate or less frequently used data exchange capabilities. The SDT continues to INCORRECTLY apply this paragraph first to control centers and now to primary control centers. Paragraph 51 is applicable to the registered the entities RCs, TOPs, and BAs and requires these registered entities to **test the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority.** The SDT continues to fail to recognize that many RCs, TOPs, and BAs already have redundancy and diverse routing of data exchange that addresses the FERC's concerns because they have voluntarily adopted this approach in meeting their COM standards compliance and their EOP-008 compliance. For these entities, testing the alternate data exchange capabilities of their backup control centers would address the FERC's concerns expressed in Paragraph 51.

As such the SDT needs to modify R21 and M21 to the following:

"R21. Each Transmission Operator shall test its alternate or less frequently used data exchange capabilities specified in Requirement R20 for redundant functionality at least once each every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]"

"M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its alternate or less frequently used data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications."

The above revisions to R21 and M21 will cause Transmission Operators to test their alternate or less frequently used data exchange capabilities specified in Requirement R20 every 90 calendar days which is the concern FERC has expressed. These changes will allow TOPs to submit evidence that the alternate or less frequently used data exchange capabilities being voluntarily used in compliance with the COM standards and EOP-008-1 have been tested to demonstrate redundant functionality (as well as alternate or less frequently use data exchage capabilities at the primary control center). The SDT should have no concern that the FERC would reject this since Paragraph 51 clearly ONLY REQUIRES THE TESTING OF THE ALTERNATE OR LESS FREQUENTLY USED DATA EXCHANGE CAPABILITIES OF THE RCs, TOPs, and BAs (regardless of the location).

While Clark is not an RC or a BA, it believes the above arguments are also applicable to these registered entities and that any similar requirements and measures applicable to these entities in IRO-002-5 or TOP-001-4 should be similarly modified.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

(1) We thank the SDT for its detailed information included in the standards' rationale boxes, as such information is useful in understanding the purpose and intent of each requirement. However, we caution that each requirement must be clear and understandable by both registered entities and auditors to demonstrate and measure compliance, respectively. We recommend incorporating aspects of these rationale boxes, within the language of each requirement, where possible.

(2) We thank the SDT for this opportunity to provide comments on these standards.

Likes 0	
Dislikes 0	

Response

Joe Tarantino - 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; - Joe Tarantino

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith

Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michael Puscas - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Thanks for all your work.	
Likes 0	
Dislikes 0	

Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

ATC agrees with the following comments put forth by NSRF.

Suggestions for the Rationale box for R20/R23:

For the paragraph that reads "The reliability objective of redundancy is to provide…." The current wording is not clear for the last sentence of the paragraph. The NSRF recommends that the last sentence of that paragraph be changed to read "For periods of planned or unplanned outages of individual components in the primary or redundant data exchange path, the requirements do not require additional data exchange infrastructure or components during those planned and unplanned outage periods".

The NSRF would like to point out the FERC Order 693, section 253 states that "…compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement…". Within TOP-001-4 there are Rational boxes (e.g. R23) that explain in detail what Redundant and

Diversely routed **MAY** mean. Without these details being within the Requirement, "Redundant and diversely routed" become ambiguous words that will allow an Entity to believe they mean one thing and an auditor may believe in something else. The NSRF recommends that the details written in the Rational box be prefaced with "Some examples of Redundant and diversely routed may mean … depending on how the responsible entity wishes to address their Redundant and diversely routed risks within their Primary Control Center".	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
For R9, the focus on this comment is based on how this relates to EMS, SCADA and associated control systems. WAPA would contend that switching to a redundant host (server, system, computer, etc) that provides functionally equivalent service, that this would not fall under the banner of a "planned outage". If an entity were to not have functionally equivalent redundant hosts and perform a switch-over, this would fall under the planned or unplanned outage banner. WAPA would like to get clarification on this as to plan appropriately for its process to meet the new standard verbiage.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	

Answer	Yes
Document Name	

Comment
While ERCOT recognizes that the SDT added the word “primary” to further specify which control center is required to include redundant and diversely routed data exchange capabilities, ERCOT requests further clarification on the term “primary Control Center.” While it can reasonably be assumed that “primary Control Center” is intended to refer to the Control Center normally used for daily, non-emergency “monitoring and control of the BES in real-time” rather than a Control Center normally used as a backup, this understanding should be explicitly stated to avoid any question as to the breadth of the standard’s scope. ERCOT asks for this clarification to ensure that a backup control center is not considered a “primary” control center during those temporary conditions in which a failover to the backup is required. If an entity lacks redundant or diversely routed data exchange capabilities at a backup control center that may temporarily function as a “primary control center” for a brief period of time, auditors might deem the entity to be out of compliance for that duration. ERCOT therefore recommends defining the term “primary Control Center” in the standard or in the NERC Glossary of Terms, as opposed to simply providing clarification in the rationale or measure, so that the clarification is more clearly enforceable. ERCOT notes that several other standards use the term “primary control center,” including EOP-008-1 – Loss of Control Center Functionality, and CIP-014-2 – Physical Security. In CIP-014-2, the “Guidelines and Technical Basis” section states that the primary control center is “the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation…” ERCOT suggests that a definition similar to that used in CIP-014-2 could provide the needed clarification. **100% Redundancy and Diversity Compliance at all times** As currently written, Requirement R2 of IRO-002-5 and requirement R23 of TOP-001-4, could still be read to require 100% system integrity at all times, no matter what events or failures may arise in an entity’s data exchange capabilities that could, for a time, cause the system to lack redundancy or diverse routing. Is an entity out of compliance with these requirements if it has redundancy built into its system and, for the majority of the time, functions properly, but temporarily fails during a broader system failure? Would an entity be considered non-compliant because the redundancy is temporarily unavailable? While the SDT sought to address this concern by adding language to the rationale box and pointed to measure language regarding evidence, neither the rationale nor the measure is enforceable. ERCOT therefore recommends adding the phrase “during normal system conditions” or “during normal system operations” to the identified requirements to clarify that entities are not required to have “additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.” Additionally, the SDT may wish to consider language similar to that used in EOP-008, R3:

“To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality”	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - 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; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Kansas City Power and Light Company greatly appreciates the work of the Standard Drafting Team. Thank you.	
Likes 0	
Dislikes 0	
Response	
Thomas Lyons - Owensboro Municipal Utilities - 3	
Answer	Yes
Document Name	
Comment	
We continuously monitor our system and the assessment provides no benefit just additional administrative work.	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	
Document Name	

Comment

For IRO-002-5

Comments: Southern believes that the language in IRO-002-5 R2 explicitly limits the scope of the requirement to “the data exchange infrastructure inside the Primary Control Center”. The first problem here is that the term “data exchange infrastructure” has no clear or broadly accepted industry definition.

The second problem is that here is no clear definition of what constitutes the control center. Is it a facility or a room inside a facility? What prevents someone from moving the “capability” outside the control center (i.e a data center not part of the control center)?

The language in IRO-002-5 R3 currently has a requirement to test the “primary control center data exchange capabilities” specified in R2” every 90 days. First of all, the terminology shifts from the word “infrastructure” in R2 to “capabilities” in R3, which leaves a lot of ambiguity. Why establish a requirement to test the redundancy of the data exchange and not the EMS platform in which the capability resides. This is perplexing given the fact that the data exchange function is, in most cases, a sub-component of the much larger distributed EMS architecture.

The language in IRO-002-5 R6 is also confusing, as it states that “each RC shall have monitoring systems that provide information utilized by the RC’s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. Again, this is very confusing, because the following questions have not been answered:

- What is meant by “particular emphasis”?
- Which “awareness systems” require redundant infrastructure
- Which “automated data transfers” are in scope?
- Which “synchronized information” is in scope?
- What level of redundancy is required? Server level, component level, network level, etc.

Likes 0	
Dislikes 0	

Response

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller	
Answer	
Document Name	
Comment	

Comments: Southern believes that the language in IRO-002-5 R2 explicitly limits the scope of the requirement to "the data exchange infrastructure inside the Primary Control Center". The first problem here is that the term "data exchange infrastructure" has no clear or broadly accepted industry definition. The second problem is that here is no clear definition of what constitutes the control center. Is it a facility or a room inside a facility? What prevents someone from moving the "capability" outside the control center (i.e a data center not part of the control center)?

The language in IRO-002-5 R3 currently has a requirement to test the "primary control center data exchange capabilities" specified in R2" every 90 days. First of all, the terminology shifts from the word "infrastructure" in R2 to "capabilities" in R3, which leaves a lot of ambiguity. Why establish a requirement to test the redundancy of the data exchange and not the EMS platform in which the capability resides. This is perplexing given the fact that the data exchange function is, in most cases, a sub-component of the much larger distributed EMS architecture.

The language in IRO-002-5 R6 is also confusing, as it states that "each RC shall have monitoring systems that provide information utilized by the RC's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. Again, this is very confusing, because the following questions have not been answered:

- What level of redundancy is required? Server level, component level, network level, etc.
- Which "synchronized information" is in scope?
- Which "automated data transfers" are in scope?
- Which "awareness systems" require redundant infrastructure
- What is meant by "particular emphasis"?

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

The NSRF would like to point out that there is a great deal of compliance information in the newly updated Rationale Boxes. We agree this gives insight to meeting the task(s) assigned to each Requirement, but does not allow for clear understanding to the applicable Entity and CEA Staff. FERC Order 693, Section 253 states that applicable Entities must meet the word of the Requirement in order to show that they are Compliant with said Requirement. The NSRF recommends that the intent of the Rationale Box be within each Requirement.

Likes 0	
Dislikes 0	

Response

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	
Response	

Consideration of Comments

Project Name: 2016-01 Modifications to TOP and IRO Standards | IRO-002-5 and TOP-001-4

Comment Period Start Date: 8/31/2016

Comment Period End Date: 10/17/2016

Associated Ballots: 2016-01 Modifications to TOP and IRO Standards IRO-002-5 AB 2 ST
2016-01 Modifications to TOP and IRO Standards TOP-001-4 AB 2 ST

There were 37 sets of responses, including comments from approximately 118 different people from approximately 91 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

The Project 2016-01 Standards Drafting Team (SDT) appreciates the careful review and constructive feedback from stakeholders. The SDT made clarifying and non-substantive changes suggested by stakeholders to the proposed Standards as follows:

- Clarified wording in the Violation Severity Level (VSL) for proposed IRO-002-5 Requirement R3 and proposed TOP-001-4 Requirements R21 and R24 (Data Exchange Capability Testing).
- Revised Rationale boxes for clarity. The Rationale boxes will be retained in the Guidelines section of the Standards upon approval of the Standards.

The revisions in proposed IRO-002-5 and TOP-001-4 address specific directives contained in FERC Order No. 817. Requirements that are not the subject of the FERC Order No. 817 directives are not in scope for the project as outlined in the Standards Authorization Request (SAR). The SDT believes the proposed Standards address the directives and provide entities with flexibility to determine how to meet the reliability objectives.

Responses to all comments are provided in the following sections.

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.

Questions

1. **Do you agree with the changes made by the SDT to draft standard IRO-002-5? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.**
2. **Do you agree with the changes made by the SDT to draft standard TOP-001-4? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.**
3. **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.**
4. **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.**
5. **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
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
					Don Cuevas	Beaches Energy Services	1	FRCC
					Stan Rzad	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
					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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
Southern Company - Southern	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Company Services, Inc.					R. Scott Moore	Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no National Grid	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	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
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Sean Bodkin	Dominion	4	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Darryl Boggess	Western Farmers	1,5	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					J. Scott Williams	City Utilities of Springfield	1,4	SPP RE
					Jim Nail	Independence Power and Light	3	SPP RE
					Jerry McVey	Sunflower	1	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					John Allen	City Utilities of Springfield	1,4	SPP RE
					Kevin Giles	Westar Energy	1,3,5,6	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Michelle Corley	Cleco Coporation	1,3,5,6	SPP RE
					Robert Hirchak	Cleco Coporation	1,3,5,6	SPP RE
					David Pham	Empire District Electric Company	1,3,5	SPP RE
Colorado Springs Utilities	Shawna Speer	1		Colorado Springs Utilities	Shawna Speer	Colorado Springs Utilities	1	WECC
					Shannon Fair	Colorado Springs Utilities	6	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Charles Morgan	Colorado Springs Utilities	3	WECC
					Kaleb Brimhall	Colorado Springs Utilities	5	WECC

1. Do you agree with the changes made by the SDT to draft standard IRO-002-5? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
We believe that Requirement R5 should identify how these non-BES facilities are determined, such as through Seasonal Assessments and other Monthly Analysis. In our opinion, in no case should this be left open ended, without bounds.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. Requirement R5 in IRO-002 is not in scope for this project. The SDT has not made changes to the requirement in approved IRO-002-4.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Xcel Energy believes that there is still some clarification needed to the definition of data exchange. Is it meant to cover data exchange between control centers (ICCP) or does this include RTUs and Communication paths?	
Likes 0	
Dislikes 0	

Response. Thank you for your comment. Proposed Requirement R2 specifies that the RC's data exchange capabilities must include reudundant and diversely routed data exchange infrastructure within the RC's primary control center. RTU's, Communication paths, and ICCP infrastructure that is outside of the RC's primary control center is not covered under Proposed Requirement R2.	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller	
Answer	No
Document Name	
Comment	
Comments: See comments below. MEAG Power voted Affirmative in error and requests that its Affirmative vote be changed to Negative for all associated ballots, Standard changes and Non-Binding opinions. MEAG Power adopts and supports the comments of Southern Company. Regards, Scott Miller, Proxy, MEAG Power, 678-644-3524	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. See response to Southern Company.	
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 limiting the scope of Requirement R2 to "the data exchange infrastructure inside the Primary Control Center" may allow for entities to circumvent the requirements by moving their data exchange infrastructure to a physical location outside of their control center (i.e., a remote data center). It is important for the SDT to ensure the reliability intent of Requirement R2 is maintained by focusing on the "data exchange capability" for the primary control center regardless of where the actual data exchange infrastructure physically resides. To remove any ambiguity, it is recommended that the SDT define the following terms:

- Data Exchange Infrastructure
- Data Exchange Capability
- Primary Control Center

In regard to R3, it is Southern Company's understanding that in most cases (including ours) that the data exchange infrastructure is an integrated component of the EMS infrastructure. Southern Company does not understand the purpose of having a requirement for redundant infrastructure for data exchange but not for the EMS.

Southern Company also requests clarification regarding the language used in IRO-002-5 R6, which states "each RC shall have monitoring systems that provide information utilized by the RC's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure." Some questions regarding the proposed requirement are as follows:

- What is meant by "particular emphasis"?
- Which "awareness systems" require redundant infrastructure?
- Which "automated data transfers" are in scope?
- Which "synchronized information" is in scope?
- What level of redundancy is required? Server level, component level, network level, etc.

Likes 0	
Dislikes 0	

Response. Thank you for your comment. The SDT agrees that the requirement should focus on maintaining the data exchange capability for the primary control center. The SDT is using the NERC defined term *Control Center* in proposed Requirement R2 to clearly indicate what infrastructure is covered by the standard. The proposed requirement cannot be circumvented by moving data exchange infrastructure to a data center because the definition of *Control Center* includes "associated data centers".

The SDT is responding to specific directives in Order No. 817 pertaining to data exchange capabilities. The SDT believes proposed Requirements R2 and R3 meet the directive and are beneficial to reliability without expansion to cover redundancy in EMS.

The SDT has not made changes to Requirement R6 (Requirement R4 in approved IRO-002-4) in addressing the directives. The requested clarifications to Requirement R6 are not in scope for Project 2016-01.

Scott McGough - Georgia System Operations Corporation - 3	
Answer	
Document Name	IRO-002-5 SOCO Comments.docx
Comment	

GSOC supports Southern Company's comments.

Questions

Do you agree with the changes made by the SDT to draft standard IRO-002-5? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.

No

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

Comments: Southern believes that the language in IRO-002-5 R2 explicitly limits the scope of the requirement to “the data exchange infrastructure inside the Primary Control Center”. The first problem here is that the term “data exchange infrastructure” has no clear or broadly accepted industry definition.

The second problem is that here is no clear definition of what constitutes the control center. Is it a facility or a room inside a facility? What prevents someone from moving the “capability” outside the control center (i.e a data center not part of the control center)?

The language in IRO-002-5 R3 currently has a requirement to test the “primary control center data exchange capabilities” specified in R2” every 90 days. First of all, the terminology shifts from the word “infrastructure” in R2 to “capabilities” in R3, which leaves a lot of ambiguity. Why establish a requirement to test the redundancy of the data exchange and not the EMS platform in which the capability resides. This is perplexing given the fact that the data exchange function is, in most cases, a sub-component of the much larger distributed EMS architecture.

The language in IRO-002-5 R6 is also confusing, as it states that “each RC shall have monitoring systems that provide information utilized by the RC’s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. Again, this is very confusing, because the following questions have not been answered:

- What is meant by “particular emphasis”?
- Which “awareness systems” require redundant infrastructure
- Which “automated data transfers” are in scope?
- Which “synchronized information” is in scope?
- What level of redundancy is required? Server level, component level, network level, etc.

Likes 0	
Dislikes 0	

Response. Thank you for your comment. The SDT agrees that the requirement should focus on maintaining the data exchange capability for the primary control center. The SDT is using the NERC defined term *Control Center* in proposed Requirement R2 to clearly indicate what infrastructure is covered by the standard. The proposed requirement cannot be circumvented by moving data exchange infrastructure to a data center because the definition of *Control Center* includes "associated data centers".

The SDT is responding to specific directives in Order No. 817 pertaining to data exchange capabilities. The SDT believes proposed Requirements R2 and R3 meet the directive and are beneficial to reliability without expansion to cover redundancy in EMS. Redundant functionality as used in Requirement R3 means that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g. switches, routers, servers, power supplies, and network cabling and communication paths between

these components in the primary Control Center for the exchange of system operating data). Redundant infrastructure is a means to achieve this objective. The SDT has not made changes to Requirement R6 (Requirement R4 in approved IRO-002-4) in addressing the directives. The requested clarifications to Requirement R6 are not in scope for Project 2016-01.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no National Grid	
Answer	No
Document Name	
Comment	
The requirements should apply to “secondary” Control Centers as well. There are times when a primary Control Center might be out of service for a prolonged length of time, and the “secondary” Control Center must have the capabilities addressed by this standard. If there is another standard that addresses “secondary” Control Centers, the Purpose of IRO-002-5 should reflect that it only applies to a primary Control Center. If IRO-002-5 is left with “primary”, then primary Control Center will need to be defined in the NERC Glossary.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The SDT believes the proposed Requirements for redundant and diverse routing of data exhange capabilities in the primary Control Centers meet the directives of Order No. 817 and benefit reliability without expansion into back-up control centers. Approved EOP-008-1 Requirements R3 and R4 specify requirements for back-up control centers. The SDT does not believe the purpose of IRO-002-5 should be changed as suggested by the commenter because other requirements in the standard are not specific to Control Centers.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE appreciates the Standard Drafting Team's efforts to develop a workable approach to requiring redundant and diversely routed data exchange infrastructure. However, Texas RE is concerned that the SDT's proposed approach limiting such diverse routing requirements solely to primary control centers is overly narrow. Texas RE requests that the SDT apply the diverse routing requirements at issue here to control centers generally, rather than to just the primary control center. However, if the SDT declines to do so, Texas RE requests that the SDT clarify the relationship between TOP-001-4 and IRO-002-5 with the backup functionality requirements set forth in EOP-008. In Order No. 693, FERC made clear that entities should possess backup capabilities that, among other things, provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center. (p. 160, &para 335). In Order No. 817, FERC further identified a clear reliability need for the reliability coordinator, transmission operator, and balancing authority to have data exchange capabilities that are redundant and diversely routed. (p. 33, ¶47). Given the clear directive that entities possess backup control centers that can replicate the reliability functions of the primary control center, it seems contrary to the general ERO-wide approach to backup functionality to only require diverse routing within primary control centers. This also appears counter to FERC's specific discussion of the relationship between the general backup functionality requirements in EOP-008 and the more specific requirements for voice communications in the COM Standards and the data exchange capability standards at issue here. Specifically, in Order No. 817, FERC made clear that the EOP-008 redundancy requirements should not supplant the diverse routing obligations to be set forth in the revised TOP and IRO compliance obligations. That is to say, although it is possible to read the EOP-008 backup functionality requirements as mandating sufficient redundancy in and of itself, FERC nevertheless called for the diverse routing reliability need to be explicitly addressed in the TOP/IRO Standards in the same manner as voice communications were addressed under the COM Standards. However, FERC's directive does not appear to contemplate simply eliminating the diverse routing requirements from the TOP/IRO Standards (and arguably to EOP-008 Standard as well) altogether.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The SDT added 'primary' to the second draft of Proposed IRO-002-5 Requirements R2 and R3 to clarify the scope of the infrastructure that must be *redundant and diversely routed*. Without this clarification, it is possible for entities to interpret the requirement to allow for infrastructure within one Control Center to provide the redundancy for the applicable entity's primary Control Center. The SDT recognizes that such an interpretation would conflict with Order No. 817 (P 48), and understands the directive to be satisfied by having redundant and diversely routed infrastructure within the primary Control Center. EOP-008 addresses requirements for back-up control centers and are not being considered by the SDT in addressing the directives in Order No. 817. The SDT has discussed their approach with FERC staff observers and believe the approach satisfies the directive.	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
See comments to question #2	
Likes 0	
Dislikes 0	
Response. Thank you for your comment.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
What does the SDT consider “data exchange infrastructure”? Without an understanding of the intent of this language, it is unclear where the expectation for “redundant and diversely routed” ends. If the intent is to require the same level of demonstration of evidence as was provided under the old COM-001-1, then redundancy typically only had to be demonstrated by showing the two separate telecomm lines going to two separate routers and then from there it went into the single firewall and then into the ESP. If the ‘primary Control Center’ is considered within the single firewall/ESP boundary, then that should be clarified further in the requirement. Suggested changes to R2: R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure after the point the data enters the Transmission Operator's primary 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.	

We also would like to see the 90 day requirement to test changed to 'Quarterly'. We have potential concerns (related to 'where' the boundary is considered for the Control Center) about which components need to be tested and what is considered an adequate test. Without knowing what components are included we may not test the right things.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. Examples of *data exchange infrastructure* in scope for the Requirement R2 are listed in the Rationale. The SDT recognizes that architectures may vary significantly between entities and consequently a more prescriptive requirement may not cover all of the reliable configurations in use. The SDT does not believe the suggested change to Requirement R2 provides additional clarity. The SDT does not support suggestions to change the testing requirement from 90-days to quarterly. The SDT believes the requirement as written provides clarity and flexibility to determine appropriate times to conduct testing, and that the interval provides reliability benefit by regularly ensuring redundant functionality is maintained. The SDT has provided clarification to the rationale section for the testing requirement to address concerns about what infrastructure needs to be tested.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
(1) We thank the SDT for responding to our request to clarify that testing of data exchange capabilities should only apply to the primary Control Center and at a required frequency greater than monthly. (2) We believe the proposed requirements should follow a more performance-based approach and utilize the associated VSLs to identify the severity of non-compliance. In its current form, a registered entity could instantly become non-compliant if these data exchange	

capabilities or associated analytical tools become unavailable. We recommend that R1 be reworded to state "Each RC shall maintain data exchange capabilities with its BAs, its TOPs, and other entities it deems necessary, to perform its Operational Planning Analyses." (3) Likewise, we recommend that R2 be reworded to state "Each RC shall maintain data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the RC's primary Control Center, for the exchange of Real-time data with its BAs, its TOPs, and with other entities it deems necessary, to perform its Real-time monitoring and Real-time Assessments." (4) We believe compliance should be embedded within existing business processes to better adopt such practices within a registered entity's operations. Many registered entities already execute or follow the execution of quarterly processes, and we believe the testing of data exchange capabilities could be included in such processes like quarterly model updates. The tracking of every 90 days could be cumbersome for registered entities to coordinate test schedules and staffing levels for adequate test participation in advance. Moreover, it may be possible that two tests are conducted within the same quarter, something the SDT is likely trying to avoid, and could fall during operating periods that are of high risk to the BES. We recommend the periodicity of these tests, as identified in R3, be changed to calendar quarters.	
Likes 0	
Dislikes 0	
Response. 1. Thank you for your comments. 2 and 3. The SDT supports using 'have' instead of 'maintain' in Requirements R1 and R2, which is consistent with wording in approved IRO-002-4 and capability-type results-based standards. The associated measures for these requirements specify that the evidence of compliance includes documentation listing data exchange capabilities, system diagrams, and system specifications. The measures do not include documentation of availability. 4. The SDT does not support suggestions to change the testing requirement from 90-days to quarterly. The SDT believes the requirement as written provides clarity and flexibility to determine appropriate times to conduct testing, and that the interval provides reliability benefit by regularly ensuring redundant functionality is maintained.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No

Document Name	
Comment	
Please see comments in response to Question #5.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment.	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
While Clark is not an RC, it believes its arguments expressed in question 2 below are also applicable to the RC and that any similar requirements and measures applicable to the RC in IRO-002-5 should be similarly modified.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	

We agree with the proposed changes but have a suggestion for a minor revision to the language of R1.

It's very hard to enforce a standard that requires the Entity to "have" data exchange capability. While we don't need to require a formal procedure document, it should be clear that to comply with the standard, the Entity will be required to provide documented evidence as set out in M1. This comment also applies to R2.

Suggested change: delete the word have and replace with document and implement

R1. Each Reliability Coordinator shall ***have document and implement*** data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning].*

Likes 0	
Dislikes 0	

Response. Thank you for your comment. The SDT supports the use of 'have' in Requirements R1 and R2 to be consistent with approved IRO-002-4 and views the requirements to be appropriately-worded results-based requirements. As noted, compliance with the standard is assessed based on evidence described in the associated measures. Consequently, the SDT does not support the suggested changes.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

R4: Is the intent of the requirement to give System Operators the authority to *deny* planned outages and maintenance of telecommunication, monitoring and analysis capabilities, in the *Real-Time Operations and Same-Day Horizons*? It is hard to see the benefit of having shift System Operators in on the approval process of planned work of this type versus dedicated support staff that can evaluate this type of work and approve or deny the work during *the Operations Planning Time Horizon*; must System Operators be involved in the approval of this type of work in the *Operations Planning Time Horizon*? The requirement is difficult to understand since 'approve' is used instead of 'deny,' and three Time Horizons are listed as applicable.

R6: The phrase 'giving particular emphasis to alarm management and awareness systems…' is vague, ambiguous, and un-measurable, and makes interpretation of the standard difficult. This type of language has historically been eliminated from several standards under the Paragraph 81 criteria. Are redundant *functionality* mentioned in R3 and redundant *infrastructure* mentioned in R6 two different things? Neither are defined terms and make interpretation of this standard more difficult.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. Requirements R4 and R6 in IRO-002 were not modified from the FERC-approved requirements and are not in scope for this project. Redundant functionality as used in Requirement R3 means that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g. switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). Redundant infrastructure is a means to achieve this objective. Requirement R6 refers to monitoring systems and the associated infrastructure. Requirement R3 is specific to data exchange capabilities.	
Michael Puscas - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe Tarantino - 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; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	DTE Energy - Detroit Edison Company, 3, Barczak Karie
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - 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; - Douglas Webb

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniel Herring - DTE Energy - Detroit Edison Company - 4

Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thomas Lyons - Owensboro Municipal Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
The comments provided by the NSRF that are applicable to TOP-001-4 are also applicable to IRO-002-5 for similar requirements.	
Likes 0	
Dislikes 0	
Response	

Mike Beuthling - Mike Beuthling On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	
Document Name	
Comment	
1. **Abstain** (standard is not applicable to HONI)	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the changes made by the SDT to draft standard TOP-001-4? If you do not agree, or if you agree but have comments or suggestions for the proposed standard provide your recommendation and explanation.	
Thomas Lyons - Owensboro Municipal Utilities - 3	
Answer	No
Document Name	
Comment	
Documented assessments every 30 minutes is an unnecessary administrative burden.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. Requirement R13 is not changed from approved TOP-001-3 and is not in scope for this project.	
Douglas Webb - 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; - Douglas Webb	
Answer	No
Document Name	
Comment	
No. The SDT revisions to the R10 Rational do not address the double criteria application created by the proposed revisions to Requirement 10. The SDT, in response to TOP-001-4 R10 Draft 1 comments, writes, “The SDT does not agree that the proposed changes to R10 affect the applicability of facilities within the CIP-002-5.1 standards.”	

Without understanding how the SDT came to their position, we have to respectfully disagree with the SDT's assessment. The issue is not R10 affecting the applicability of facilities within CIP-002-5.1; the issue is R10 may create compliance obligations under CIP-002-5.1. When a non-BES Facility can adversely impact reliability is identified under R10; it essentially becomes a BES Facility ("Converted non-BES Facility", our term for purposes of these comments). The STD's comments confirm this view, writing, "The SDT agrees that analyses performed in support of BES inclusions can identify some non-BES facilities that should be monitored for reliability…" The Converted non-BES Facility now is treated as a BES Facility, falling within the CIP-002-5.1 Applicability Sec. 4.2.2., "All BES Facilities." As a BES Facility, Entities are required to evaluate the Facility under CIP-002 to determine whether it is a High, Medium, or Low Impact BES Cyber System. **Our Concern** Bringing the BES Facility into CIP-002-5.1 Applicability creates a double impact criteria situation. In other words, not identifying the non-BES Facility as potentially impacting the BES under R10—a compliance failure—automatically creates another compliance failure under CIP-002-5.1 because all BES Facilities are to be categorized and, as required, protected. Put another way, in the event a non-BES Facility impacting the BES is not identified under R10 and should have been—it was missed—the Entity would be hard-pressed to justify that CIP-002-5.1 only applies to the non-BES Facilities identified under R10 and not to the "missed" Facilities. It would have to be a common sense justification but from a real-world view, the proposition is difficult to defend. *The current Proposed Standard creates the situation that a compliance failure with R10 creates a compliance failure under CIP-002-5.1.* **Suggestion to Address the Issue** We do not believe this is an instance when the issue can be addressed by a single SDT; it requires the CIP Modifications SDT and potentially others, current and the future, to consider how revisions align with other Standards and the potential for a double impact criteria situation.

Likes 0	
Dislikes 0	

Response. Thank you for your comment. Monitoring a non-BES facility as required by Requirement R10 does not automatically result in the facility becoming part of the BES. The BES definition and Exceptions process determine what facilities are part of the BES. Requirement R10 does not determine what facilities are part of the BES. The Project 2016-01 Standards Authorization Request (SAR) establishes the SDT's responsibility for addressing the Order No. 817 directives.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Please see comments in response to Question #5.	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
For R9, the focus on this comment is based on how this relates to EMS, SCADA and associated control systems. WAPA would contend that switching to a redundant host (server, system, computer, etc) that provides functionally equivalent service, that this would not fall under the banner of a "planned outage". If an entity were to not have functionally equivalent redundant hosts and perform a switch-	

over, this would fall under the planned or unplanned outage banner. WAPA would like to get clarification on this as to plan appropriately for its process to meet the new standard verbiage.

For R20, The verbiage that was changed in the rationale raises concerns as it relates to how this will be audited. Data Exhcange Infrastructure is used in both the Rationale, the Requirement, and the Measure. Yet the Rationalse provides signinficantly more detail and yet at the same time a wider scope. The concern is focused on the items listed in the Rationale:

(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)

The first example of concern with this verbiage is that the Requirement and the Standard focuses on "*redundant and diversely routed data exchange infrastrcuture*" but the Rationale seems to expand the scope of this to focus on components of devices instead of the devices themselves. To draw a logical leap, would an entity be expected to have devices with redundant power supplies or is redundant power into the control center sufficient. WAPA would like to see the Rationale match the Standard and Measure verbiage. The other seemingly untouched area is the discussion around technology that make redundant paths much less effective or possibly not needed at all. If, for example, a group of entities were to have a cloud technology (lets use MPLS for example) infrastructure that provides redundancy; would this meet the letter of the law even though redundancy at a device level may not exist? This may not necessarily meet compliances as described but provides the level redundancy that the standard is striving for. WAPA feels the focus on redundant and diverse links may cause the industry to miss the wider use of many technogologies available to us because we would be focused on meeting compliance rather than engineering a reliable and effective solution.

Likes 0	
Dislikes 0	

Response. Thank your for your comment.

Requirement R9 is not in scope for Project 2016-01.

The SDT's intent is to preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. The SDT is not prescribing any particular design approach. The SDT did not did not intend for the rationale for Requirements R19 and R20 (and R22 and R23) to imply a need for redundancy at an internal component (i.e. internal power supply) level. For example, if a power supply to Server A fails then an acceptable approach is to fail over to Server B which has its own power supply.

The SDT believes the requirements for redundancy and diversely routed data exchange infrastructure provide entities with flexibility to implement effective solutions that meet their system needs within existing and foreseeable technologies and achieve the reliability objectives in Order No 817. The SDT notes that the defined term *Control Center* includes associated data centers, which could support non-traditional architectures that provide redundancy.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

(1) We thank the SDT for responding to our request to clarify that testing of data exchange capabilities should only apply to the primary Control Center and at a required frequency greater than monthly.

(2) We caution the SDT in its phrasing of language used to address a FERC directive requiring TOPs to monitor non-BES facilities, as deemed necessary by the TOPs, to fill their functional obligations. Rather than dive into a philosophical discussion regarding States rights versus the jurisdiction of FERC, we focus our concerns on the practical application of this language. Many of the non-BES facilities are owned and maintained by entities not listed within the NERC compliance registry. Some of these non-registered entities were de-registered following the approval of the Risk-based Registration initiative. Moreover, owners of non-BES facilities outside a TOP Area may not have direct business ties or incentives to coordinate with the TOPs. We recommend removing non-BES facility references from these standards, or as an alternative, rephrasing the appropriate parts of R10 to monitor and obtain statuses, voltages, and flow data for non-BES facilities, when such information is available.

(3) Moreover, we continue to have concerns that the proposed additional requirements require a registered entity to possess data exchange capabilities and not maintain such capabilities. By focusing on possession, a registered entity could instantly become non-compliant if these data exchange capabilities or associated analytical tools become unavailable. We believe the requirements should follow a more performance-based approach and utilize the associated VSLs to identify the severity of non-compliance. For instance, we propose rewording Requirement R19 to "Each TOP shall maintain data exchange capabilities with entities it deems necessary to perform its Operational Planning Analyses." This proposal could be reused to modify the similar BA requirement, R22.

(4) Likewise, we propose rewording Requirement R20 to "Each Transmission Operator shall maintain data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, needed to perform Real-time monitoring and Real-time Assessments." This proposal could be reused to modify the similar BA requirement, R23.

(5) We feel compliance should be embedded within existing business processes to better adopt such practices within a registered entity's operations. Many registered entities already execute or follow the execution of quarterly processes, and we believe the testing of data exchange capabilities could be included in such processes like quarterly model updates. The tracking of every 90 days could be cumbersome for registered entities to coordinate test schedules and staffing levels for adequate test participation in advance. Moreover, it may be possible that two tests are conducted within the same quarter, something the SDT is likely trying to avoid, and could fall during operating periods that are of high risk to the BES. We recommend the periodicity of these tests, as identified in R21 and R24, be changed to calendar quarters

(6) We believe the use of the NERC-defined Glossary Term, Operating Plan, is incorrectly applied in Requirement R22. To paraphrase, an Operating Plan is a group of activities, Operating Procedures, or Operating Processes that are used to achieve a goal. In the case of this requirement, what is the goal a BA assessing its next-day operations trying to achieve? We recommend avoid using the NERC glossary term in this context or use a NERC defined term like "Adequacy."

(7) In light of the removal of operating logs as evidence identified within Measures M20 and M23, we ask the SDT to reflect this removal in the Evidence Retention Section of this standard (i.e. Section C.1.2).

Likes 0	
Dislikes 0	

Response. 1. Thank you for your comment.

2. Requirement R10 responds to FERC directives requiring TOPs to monitor non-BES facilities necessary for determining SOL exceedances. The SDT recognizes 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. When the non-registered entity is outside the TOP area, another TOP that also needs data from this facility could be a source for obtaining the data.

3 and 4. The SDT supports using 'have' instead of 'maintain' in Requirements R19, 20, R22, and R23, which is consistent with wording in approved TOP-001-3 and capability-type results-based standards. The associated measures for these requirements specify that the evidence of compliance includes documentation listing data exchange capabilities, system diagrams, and system specifications. The measures do not include documentation of availability. 5. The SDT does not support suggestions to change the testing requirement from 90-days to quarterly. The SDT believes the requirement as written provides clarity and flexibility to determine appropriate times to conduct testing, and that the interval provides reliability benefit by regularly ensuring redundant functionality is maintained. 6. Approved TOP-002-4 Requirement R4 specifies that each BA must have an Operating Plan for next day operations. Proposed TOP-001-4 Requirement R22 addresses data exchange capabilities necessary for developing this Operating Plan. Although the wording has changed, BAs had this obligation under approved TOP-001-3 Requirement R20 which covered the BA's data exchange capabilities in the Operations Planning, Same-day Operations, and Real-time operating horizons. In proposed TOP-001-4, Requirement R22 addresses the BA's data exchange capabilities for the Operations Planning time horizon, and Requirement R23 addresses the BA's data exchange capabilities for the Same-day Operations and Real-time operating horizons. 7. The SDT has made the requested change.

Chris Gowder - 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; - Chris Gowder, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA believes the meaning of redundant and diversely routed remains unclear, and that entities (and auditors) would benefit from having some examples of configurations that meet the expectations. Does a failover configuration where there is a potential for multiple combinations of active (or live) components meet the redundancy and diversely routed requirement, or does it require a completely	

separate set of isolated components from top to bottom? For example, a primary server could be setup to be capable of using either a primary and secondary switch. The secondary server would be setup the same way, so at any given time a combination of primary and secondary devices could be active. The boundary of what is considered within the Control Center is also unclear. Entities are currently having to decipher what is required or proposed to be required by the CIP standards, which involve the very same equipment being discussed here. It is vital that the various Subject Matter Experts involved in the two efforts speak the same language and have a common understanding of what is meant by words such as “failure or malfunction” and “redundant and diversely routed”. We believe there is too much room for interpretation as the Requirements are currently worded.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The configuration described by the commenter whereby at any time both the primary and secondary servers are active could be an example of redundancy provided the arrangement "will provide continued functionality despite failure or malfunction" of one of the servers, as explained in the Rationale for Requirement R20. The SDT believes that the description in the rationale provides suitable guidance for entities to use in understanding the requirement and covers the full range of potential solutions, unlike specific examples which will only clearly indicate some architectures out of the myriad of suitable approaches for complying with the requirement. The SDT does not see conflicts between the proposed requirements and CIP standards.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
We would like to see some changes in the Rationale for R10 to clarify that the intent is to monitor the non-BES facilities ‘so that a TOP can determine SOL exceedances’ not just monitor non-BES facilities. We think clarifying also that the reliability impact to be guarded against is impact on the BES, not on the non-BES facilities. Please make the following change: The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact BES reliability are monitored.	

A similar change would also be helpful in the following sentence:

The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances on BES Facilities within its Transmission Operator Area.

What does the SDT consider “data exchange infrastructure”? Without an understanding of the intent of this language, it is unclear where the expectation for “redundant and diversely routed” ends. If the intent is to require the same level of demonstration of evidence as was provided under the old COM-001-1, then redundancy typically only had to be demonstrated by showing the two separate telecomm lines going to two separate routers and then from there it went into the single firewall and then into the ESP. If the ‘primary Control Center’ is considered within the single firewall/ESP boundary, then that should be clarified further in the requirement.

Suggested changes to R2:

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure after the point the data enters the Transmission Operator's primary 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.

We also would like to see the 90 day requirement to test changed to ‘Quarterly’.

We have potential concerns (related to ‘where’ the boundary is considered for the Control Center) about which components need to be tested and what is considered an adequate test. Without knowing what components are included we may not test the right things.

Likes 0	
Dislikes 0	

Response. Thank you for your comment. The SDT has made a requested clarification to the Rationale second paragraph for Requirement R10. The SDT did not think the proposed change to "SOL exceedances *on BES Facilities*" improved clarity over the existing wording which uses the defined term SOL.

Examples of *data exchange infrastructure* in scope for the Requirements R20 and R23 are listed in the associated Rationale. The SDT recognizes that architectures may vary significantly between entities and consequently a more prescriptive requirement may not cover all of the reliable configurations in use. The SDT does not believe the suggested change to Requirement R20 provides additional clarity.

The SDT does not support suggestions to change the testing requirement from 90-days to quarterly. The SDT believes the requirement as written provides clarity and flexibility to determine appropriate times to conduct testing, and that the interval provides reliability benefit by regularly ensuring redundant functionality is maintained. The SDT has provided clarification to the Rationale sections for the testing requirements to address concerns about what infrastructure needs to be tested.

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
We agree with the overall objective of the proposed revisions to the standard to ensure accurate system modeling for Real-time Assessment and real-time monitoring along with driving towards reducing the impacts to those processes of single points of failure for data systems. However, the proposed verbiage changes from the previously balloted standard concerning testing frequency in R21 and R24 does not go far enough to differentiate between situations where redundant internal data exchange capability is provided in an active-active configuration versus an active-standby configuration. In an active-active configuration the redundant internal data exchange capability is being tested through the ongoing use and monitoring of the equipment providing the redundant capability. In an active-standby configuration the equipment providing the redundant internal data exchange capability is not being continually tested and warrants an explicit testing requirement. The quarterly testing requirement for an active-standby configuration is appropriate. In an active –active configuration no dedicated testing is necessary at any scheduled intervals since equipment is continually being tested through use and monitoring. This approach encourages an active-active configuration which clearly provides enhanced reliability since there are no potential gaps where redundant capability is lost and not recognized until the next test.	
Likes 0	
Dislikes 0	

Response. Thank you for your comment. Proposed requirements for testing data exchange capabilities respond to the Order No. 817 directive and provide reliability benefit by periodically testing and verifying the redundant functionality of an entity's data exchange capabilities. The SDT is not prescribing how an entity is to test its data exchange capabilities for redundant functionality. A test for redundant functionality must demonstrate that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g. switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data).

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Please see Texas RE's response to the #1 regarding the specificity of primary control centers. The same concerns apply to IRO-002-5. Texas RE noticed TOP-001-4 Requirements R19 and R22 do not specify data exchange capabilities, with redundant and diversely routed data exchange infrastructure. Requirements R20 and R23 do specify data exchange capabilities, with redundant and diversely routed data exchange infrastructure. Is it the SDT's intent that the data TOPs and BAs use to develop an Operations Planning Analysis not be redundant and diversely routed?

Likes 0	
Dislikes 0	

Response. Thank you for your comment. See response provided in previous section.

The SDT does not intend to require redundant and diversely routed data exchange capabilities for purposes of performing Operational Planning Analysis.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no National Grid

Answer	No
Document Name	

Comment	
TOP-001-4 Requirement R10 is redundant with IRO-002-5 requirmeent R5. Both refer to the moinitoring of facilities. The revisions to the Rationale for Requirement R10 reinforce this.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. TOP-001-4 Requirement R10 applies to TOPs, while IRO-002-5 Requirement R5 applies to RCs. The requirements are not redundant.	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	

Requirement R20:

NSRF revisions add further clarity to redundant and diversely routed within the Requirement. It's important to maintain a balance between being specific and overly prescriptive in a mandatory zero-defect environment. We suggest the following revision allows entities to clearly define two primary control center data paths and the flexibility to identify what needs to be redundant while meeting FERC's objectives. Allowing entities to define two data infrastructure paths also recognizes that auditing to all possible single points of failure isn't realistic or feasible.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant (meaning at least two data exchange paths exist for normal operating conditions) and diversely routed data exchange infrastructure (meaning switches, routers, file servers, power supplies, and network cabling in communication paths between these components in the two identified data exchange paths) within the Transmission Operator's primary 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. The planned or unplanned loss of one of the two data exchange infrastructure paths does not require further actions to meet compliance.

Requirement R23: The following suggested revisions makes R23 consistent with the revisions suggested for R20. **R23.** Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure (meaning switches, routers, file servers, power supplies, and network cabling in communication paths between these components in the two identified data exchange paths) within the Balancing Authority's primary Control Center, 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 analysis functions. Suggestion for R21 and R24: The NSRF thanks the drafting team for changing the periodicity for testing data exchange capabilities from the previous monthly periodicity. NSRF recommends changing the revised 90-day testing periodicity to **quarterly**. While the industry appreciates standardization, there is a benefit to changing 90 days to **quarterly**. This avoids continually accelerated tracking and rotating compliance periods. Operationally, moving to the largest testing period to maintain adequate reliability allows personnel flexibility in scheduling, tracking, and completing work. Quarterly is superior to 90-days, Bi-annual is superior to 6-months, and annual is best unless a specific reliability need is identified.

Likes 0	
Dislikes 0	

Response. Thank you for your comment. The SDT agrees that an entity could define two data paths as a potential approach to achieving the reliability objective of the Order No. 817 directive. As written, Requirements R20 and R23 in proposed TOP-001-4 do not preclude this approach. However, the revisions proposed by the commenter could limit some flexibility by specifying *how* an entity must achieve the objective, and create an unneccessary obligation to designate data paths. The SDT believes the Requirements and supporting Rationale as written satisfy the FERC directives and provide clear obligation for applicable entities. The SDT does not support suggestions to change the testing requirement from 90-days to quarterly. The SDT believes the requirement as written provides clarity and flexibility to determine appropriate times to conduct testing, and that the interval provides reliability benefit by regularly ensuring redundant functionality is maintained.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
TOP-001-4 R20 - Please see comments regarding data exchange capabilities noted in Question #1.	
Likes 0	
Dislikes 0	
Response. See response in previous section.	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	FERC Order.jpg
Comment	

ATC is concerned regarding requirement 10.3 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 our 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 oeprating parameters, whether impedances, charging values or ratings, or we do not have the correct telemetry, we cannot monitor their facilities (e.g., confirm flows are within limits). 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 they are not required to provide it monitoring is not feasible and thus not required.

Requirement 20 was modified to indicate the need for redundant and diversely routed data exchange capabilities within the TOPs primary control center. The way the standard is written ignores the enhanced redundancy ATC has implemented between control centers such that we can survive the loss of a single control center. I believe it is contrary to the intent of the commission order (see below) which requires that "the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing". I would recommend that the SDT modify the wording to allow for TOPs or BAs that have implemented redundancy across multiple primary control centers.

Requirement 21 was modified such that data exchange capabilities used in the primary Control Center have to be tested once every 90 days. The SDT did extend that from every 30 days which was a positive result of the first round of comments. Since ATC's redundancy is built into the overall system architecture, where the loss of an entire control center can be withstood, verifying capabilities within one or both of our centers is above and beyond the intent of the FERC order (attached).

ATC agrees with the following comments put forth by NERC Stansdards Review Forum (NSRF).

Suggestions for Requirements R20 and R23:

The term 'redundant and diversely' routed is undefined and ambiguous. NSRF suggests the following wording change for these two requirements: "Each Balancing Authority (TOP) shall have data exchange capabilities, with redundant and diversely routed that reduce or mitigate single points of failure of data exchange infrastructure within the Balancing Authority's(TOP) primary Control Center in the exchange of identified Real-time data" . The NSRF believes that this suggested language can also be applied to other Entities that require a reduction of single points of failure.

Suggestions for R21 and R24:

The NSRF thanks the drafting team for changing the periodicity for testing data exchange capabilities from the previous monthly periodicity. Within the comments to the first round of comments the drafting team indicated that they had moved the periodicity to quarterly, but actually put in 90 days. This may sound like a small thing, but from a compliance standpoint tracking 90 day periodicity versus a quarter periodicity can be a big thing. If an entity tracks by a quarter and completes their testing on a 91st day of a 91 day quarter, they are out of compliance. In addition, our technicians that test would find it less of a compliance burden to track quarter

testing than tracking 90 day intervals. We would suggest that the wording in these two requirements actually use the term “quarter” or “quarterly”.	
Likes 0	
Dislikes 0	

Response. Thank you for your comment.

Requirement R10 responds to FERC directives requiring TOPs to monitor non-BES facilities necessary for determining SOL exceedances. The SDT recognizes 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. The SDT does not support the suggested change because it could adversely impact reliability by allowing facilities that are necessary for determining SOL exceedances to go unmonitored.

The SDT recognizes that data exchange architectures that rely on other control centers to provide redundancy to the primary Control Center do not meet the requirement of proposed TOP-001-4 Requirement R20 and R23. In Order No. 817, FERC indicated that requirements for back up control centers in EOP-008 did not "supplant the redundancy requirements" for voice or data communications. The SDT believes the proposed TOP-001-4 Requirements R20 and R23 directly address Order No. 817 directive (P 47) and benefit reliability by assuring TOPs have redundant and diversely routed data exchange capabilities within the primary Control Center. The SDT has discussed their approach with FERC staff observers and believe the approach satisfies the directive. The SDT notes that the definition of Control Center includes associated data centers.

Proposed TOP-001-4 Requirements R21 and R24 address the Order No. 817 directive for testing redundant functionality of data exchange capabilities used in primary Control Centers. (P 51)

See response to MRO NSRF for additional comment response.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No

Document Name	
Comment	

R16, R17: See our comment regarding R4 of IRO-002-5 above.

R20-R24: Redundant infrastructure and redundant functionality terms are again used in different requirements. An entity can have redundant functionality without redundant infrastructure. For example, you can have a single router/switch/piece of network equipment with redundant paths/functionality, but if power to the switch is lost then the functionality is lost because you don't have redundant infrastructure.

R21: It is not clear what is required to test redundant functionality. This could include each piece of network infrastructure inside the primary control center (ICCP boxes, routers, switches, EMS computers, System Operator computer consoles, etc.) If this is left vague then it is not a good fit for a standard, but should be considered a guideline.

R21-24: We request further clarification/explanation from the drafting team on the extent of the testing addressed in R21. Is it the drafting team's intent to require an entity to test an entire pathway for redundant functionality every 90 calendar days, or is testing required on single elements only? The language in the requirement does not specifically address the extent of the testing expected. We recommend that language clearly outlining the extent of testing necessary to achieve compliance necessary be inserted in the requirement(s) or perhaps further explanantion in the rationale.

Also, Duke Energy is unsure that the proposed requirements R20-R24, do not fit with the overall purpose of the TOP standard family. The purpose outlined in TOP-001-4 states:

"To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences."

We do not believe that the required actions in R20-R21 and R23-R24 are placed appropriately in this standard. We are in agreement that some of the actions may be deemed necessary, however, we are not convinced that said actions would prevent instability, uncontrolled separation, or Cascading outages that may adversely impact reliability of an Interconnection. Duke Energy suggests the drafting team consider another standard, perhaps TOP-003-3, for the directed requirements. TOP-003-3 aligns better with these new requirements instead of being placed in TOP-001-4 and suggest moving R19 and R22 from TOP-001-4 to TOP-003-3 also (these requirements are currently R19 and R20 in TOP-001-3).

Likes 0	
Dislikes 0	
Response. Thank you for your comment. For R16, R17 comment, see response in previous section. R20-R24. The SDT confirms that the terms *redundant infrastructure* and *redundant functionality* are used as intended in the requirements and rationale. Redundant functionality as used in Requirement R21 and R24 means that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g. switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). Redundant infrastructure is a means to achieve this objective. R21. The SDT has provided clarification to the rationale section for the testing requirement to address concerns about what infrastructure needs to be tested. The proposed requirement addresses Order No. 817 directives (P 51). R21-24. The proposed requirements and rationale provide an entity with flexibility to design a testing program to meet operational needs, provide assurance of redundant functionality, and meet the requirements and FERC directives. Testing the entire pathway every 90 days is not specified in the requirement. The SDT determined that modifying the data exchange requirements in approved TOP-001-3 (R19 and R20) provided an efficient approach to addressing the directives in Order No. 817, rather than transferring data exchange requirements and introducing new requirements into TOP-003.	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	

NVE still has concerns with the identification of non-BES facilities. The proposed TOP-001-4 RSAW requires the Transmission Operator to provide evidence that it monitored all the data for non-elements identified, but no guidance on evidence to show that we do or do not have non-BES facilities. Would we need to provide studies to show that we have no non-BES facilities? We also have concerns about how non-BES facilities outside the Transmission Operators Area should be identified by the TOP. Some sort of methodology or guidance should be added to the Requirement to demonstrate the identification of non-BES facilities.

Likes 0	
Dislikes 0	

Response. Thank you for your comment. The rationale for Requirement R10 and the draft RSAW include examples of studies or analyses performed by TOPs that could lead to identifying non-BES facilities that should be monitored for determining SOL exceedances. The requirement provides flexibility for entities to determine their own methods or techniques to satisfy the objective. Entities may establish a methodology or guidance for identifying the non-BES facilities that they need to monitor, however the SDT does not believe that the standard needs to prescribe this approach.

Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities

Answer	No
Document Name	

Comment

R10.4, R10.5, & R10.6 duplicate the requirements in the already approved TOP-003-3, R1.

R19 & R20 overlap with the requirements in the already approved TOP-003-3, R5.

Likes 0	
Dislikes 0	

Response. Thank you for your comment.

TOP-003-3 Requirement R1 specifies that TOPs must have a data specification for the data needed to perform its Real-time monitoring, Real-time Assessments, and Operational Planning Analysis. Proposed TOP-001-4 Requirement R1 specifies that the TOP must perform monitoring as described in parts 10.1 to 10.6. These requirements are not duplicative. Proposed TOP-001-4 Requirements R19 and R20 address Order No. 817 directives for TOPs to have data exchange capabilities and correspond to approved TOP-001-3 Requirement R19. TOP-003-3 Requirement R5 requires entities that receive a data specification to satisfy their obligations. These requirements are not duplicative.
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller

Answer	No
Document Name	
Comment	
Comments: See comments below.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
R10. In the previous version of TOP-001-4, R10 required TOPs to monitor non-BES facilities necessary for determining SOL exceedances both within and outside its footprint "identified as necessary by the TOP." This has been broadened to include the RC with the	

introduction of new text in the “Rationale for Requirement R10” box; which states that any of the following could lead to an identification of non-BES facilities that should be monitored:

1. APS OPA
2. APS RTA
3. APS analysis to determine BES Inclusion Exceptions
4. Peak RC analysis performed in support of outage coordination (requiring temporary monitoring)

This is problematic for several reasons:

1. The RC model may not be as robust as the TOP’s model for non-BES facilities. Therefore, the RC’s ability to determine which non-BES facilities affect the BES is limited without TOP input. A "vetting" process should be added whereby the RC must validate the non-BES facilities to be added with the TOP.
2. Temporary monitoring of non-BES facilities, if the IT infrastructure is not already in place, may not be feasible depending on the lead time available in the RC’s outage coordination process; particularly if the facilities are not already modeled and/or the data is not readily available. For example, in the Western Interconnection, Peak Reliability initiates their OPA studies only two days before the scheduled outage.

At a minimum, if support of the RC outage coordination process is to remain as part of requirement R10, then the text of the requirement should be expanded to specifically include the RC: “**identified as necessary by the TOP or by the RC in support of their outage coordination process**.”

R20 and R23. The introduction of the word “primary” as a clarifier to Control Center is problematic in that it limits where the an entity may locate its “redundant and diversely routed data exchange infrastructure” to that within the “primary Control Center.” As APS has redundant and diversely routed data exchange infrastructure *across* (and not *within*) Control Centers; i.e. infrastructure that spans our primary and back-up Control Center locations, the requirement as written limits flexibility in terms of where redundant infrastructure may be located. As worded, this would require entities to install additional redundancy within its primary Control Center location.

If the SDT’s intent is to ensure the reliability of data exchange structure used to maintain its data exchange operations within the primary control Center, we propose modifying the language as follows to recognize redundant data exchange capability infrastructure across an entity’s *collective* Control Center facilities:

APS Proposed R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure **used to maintain its operations** within the Transmission Operator's primary 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. **APS Proposed R23**. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure **used to maintain its operations** within the Balancing Authority's primary Control Center, 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 analysis functions.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. R10. The SDT included examples of analyses and studies that could lead to the identification of non-BES facilities that should be monitored for determining SOL exceedances. The SDT believes the RC's outage coordination process is a potential source of information, studies, or analysis that the TOP could use to support the TOP's determination. The SDT changed the rationale to clarify that the TOP makes this determination for the purposes of the TOP's monitoring specified by Requirement R10. The SDT believes the proposed requirement addresses the Order No. 817 directive (P 35-36) and provides flexibility for TOPs to determine how to temporarily monitor non-BES facilities needed for determining SOL exceedances. R20 and R23. The SDT recognizes that data exchange architectures that rely on other control centers to provide redundancy to the primary Control Center do not meet the requirement of proposed TOP-001-4 Requirement R20 and R23. In Order No. 817, FERC indicated that requirements for back up control centers in EOP-008 did not "supplant the redundancy requirements" for voice or data communications. The SDT believes the proposed TOP-001-4 Requirements R20 and R23 directly address Order No. 817 directive (P 47) and benefit reliability by assuring TOPs have redundant and diversely routed data exchange capabilities within the primary Control Center. The SDT has discussed their approach with FERC staff observers and believe the approach satisfies the directive. The SDT notes that the definition of Control Center includes associated data centers. The SDT does not agree with the suggested changes to R20 and R23 for these reasons.	
Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	
Answer	No

Document Name	
Comment	

Oncor's comments have no change from the last draft as there is no change to the Standard Requirement in this draft. Revisions made in rationale boxes do not change the requirement and often are removed when the Standard becomes effective.

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	

Response. Thank you for your comment. The SDT's Rationale are retained in the Supplemental Material section of the standard, once approved, and is included in the draft Reliability Standards Audit Worksheets during standards development.

The SDT is using 'monitor', 'obtain and utilize', and 'identified as necessary by the Transmission Operator' in the same manner as they are used in approved TOP-001-3. The format of Requirement R10 has been changed in proposed TOP-001-4 for clarity. The SDT did not add new requirements to Requirement R10 for Remedial Action Schemes; these monitoring requirements are carried over from approved TOP-001-3. Requirements for TOPs to develop data specifications and for entities to provide data to the TOP are covered under approved TOP-003-3.

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
For Requirement R10.6 we are concerned how non-BES facilities outside the Transmission Operator Area should be identified by the TOP? We believe that this should be specified. This is partly mentioned in the Rationale for Requirement 10; but is not part of this requirement. The requirement should be set up to complement the other standards' requirements.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. In the rationale for proposed Requirement R10, The SDT included examples of analyses and studies that could lead to the identification of non-BES facilities that should be monitored for determining SOL exceedances. The SDT does not support adding a prescriptive requirement to specify how non-BES facilities should be identified.	

Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	
Comment	

R20 Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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.

{C}1. {C}This requires redundancy and diverse routing only within the Transmission Operator’s primary control center. The communication links referenced could easily cover hundreds of miles, and they can only be well protected during the last few hundred feet within an entities facilities. This requirement says you must have redundancy and diversity for the short and well controlled portion, but not for the much longer, less controlled, and thus more vulnerable portion. I cannot see a technical basis for this approach.

{C}2. {C}The term “diversely routed” as applied to the area within a Control Center is not well defined. For example, can the two cables be within the same cable tray for a short distance? If so, for how long?

{C}3. {C}The extent of redundancy required is not clear. Would this require redundancy in the servers that are the source of the data, would it require redundant Ethernet ports on such a server, would it require redundancy in the power supplies supporting the equipment? All these questions (and more) must be answered for an entity to design a compliant solution.

{C}4. {C}Has any work been done to determine how frequently a failure within a control center is the cause of a data communications failure? It would seem necessary to do something like that before implementing this requirement.

{C}5. {C}The rationale implies that failure to have redundant facilities in place when one set of facilities is being upgraded is not a violation of the requirement, but there is nothing in the actual requirement to support that. That is not an appropriate use of the rationale section. Consider adding the following at the beginning of the requirement: “Except during planned outages of less than two weeks duration and during unplanned outages, . . . ”

{C}6. {C}This requirement is focused on infrastructure. It is not clear how the availability of a completely different approach to the data exchange might meet this requirement. If the data set was small enough that it could be verbally exchanged via telephone, faxed, emailed, or FTP’d to the other party, would that meet the requirement? Consider rewording the requirement to state the objective more broadly and therefore allow these approaches to be used to meet compliance.

{C}7. {C}The requirement does not take into account variability in the criticality of the data. Where failure of a data link to one entity might be a minor annoyance, failure of a link to another might be catastrophic. This requirement allows no flexibility in matching the degree of redundancy and diversity to the associated risk of the loss of the data. Consider giving the TOP latitude to determine the appropriate level of redundancy for a particular link, particularly in consideration of the criticality of the data and the reliability of various parts of the data exchange infrastructure.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

1. The second sentence in the second paragraph should not be part of the rationale of the standard. The rationale should include the reasoning behind the standard. This statement attempts to add an element to the requirement and thus should be part of the requirement. As it stands now it will introduce confusion over whether incorporating various failure modes is mandatory or advisory.

2. Similarly the third sentence in the second paragraph should not be part of the rationale of the standard. If an actual event can be substituted for a test, that should be made part of the requirement as it is done in other standards. See CIP-009, R2 for an example of how this can be accomplished correctly.

Likes 0	
Dislikes 0	

Response. Thank you for your comment.

Requirement R20.
1. Proposed TOP-001-4 Requirement R20 addresses Order No. 817 directive (P 47). The SDT believes the requirement provides a reliability benefit by reducing risks that a single point of failure with a primary Control Center could halt the flow of real-time data to operators. The requirement is consistent with the functional model and applicable entity's jurisdiction.

2,3. The SDT believes the proposed requirement and supporting rationale establishes the reliability objective for *redundant and diversely routed data exchange capabilities* while providing TOPs flexibility for determining how to meet the objective within the constraints of the entities facilities and systems. The SDT's intent is to preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. The SDT is not prescribing any particular design approach. The SDT did not intend for the rationale for Requirements R19 and R20 (and R22 and R23) to imply a need for redundancy at an internal component (i.e. internal power supply) level. For example, if a power supply to Server A fails then an acceptable approach is to fail over to Server B which has its own power supply.

4. The SDT has not performed such a review. Proposed TOP-001-4 Requirement R20 addresses an Order No. 817 directive (P 47).

5. The SDT believes the rationale addresses this concern. The rationale remains in the supplemental material section of the standard, once approved. Further, Measure M20 is drafted to support the SDT's intent for Requirement R20. The associated measure specifies that the evidence of compliance includes documentation listing data exchange capabilities, system diagrams, and system specifications.

6, 7. The proposed requirement addresses the TOP's data exchange capabilities in the primary Control Center for performing Real-time monitoring and Real-time Assessments. It is a capability-type results-based requirement. Issues with small data set discrepancies or criticality of data that could be resolved by operating procedures are not covered under the proposed requirement. However approved TOP-010-1 - Real-time Monitoring and Analysis Capabilities Requirement R1 could apply to the described scenarios.

Rationale for Requirement R21

1,2. The SDT is including this in the rationale section to provide entities context and insight of the SDT's intent. The rationale becomes part of the Supplemental Material section of the standard, once approved. The proposed requirement, with supporting rationale, provide an entity with flexibility to design a testing program to meet operational needs, provide assurance of redundant functionality, and meet the requirement.

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Requirement 20 defines the needs for "data exchange infrastructure". SRP feels that this is prescribing a technology solution for the need for redundant and diversly routed data exchange capabilites that is implied. Entities must be responsbile for determining the method for obtaining compliance. The standards need to refrain from defining a solution that may be difficult to obtain for all entities.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The SDT has worded the proposed requirement to describe the reliability objective without being prescriptive as to how entities are to achieve the objective. Order No. 817 directs NERC to revise the standards to require redundant and diversely routed data exchange capabilities, and this will require data exchange infrastructure.	
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. The Time Horizon for R10 is "Real-Time Operations", and while the monitoring of non-BES facilities may be accomplished in Real-Time, their identification *cannot* be. Some sort of methodology or guidance should be provided for the monitoring of non-BES facilities and the associated data, specifically data from outside the Transmission Operator's area. As previously stated, rather than developing additional requirements which would not likely be beneficial, we continue to believe a more prudent approach is to focus on the desired end state itself. We still believe the argument can still be made that our existing obligations, when considered as a whole, could collectively appease FERC's concerns. While we appreciate the SDT's recent revisions which no longer requires monthly testing, we once again recommend using the text "once a calendar quarter" rather than "every 90 calendar days" as is most recently proposed.	
Likes 0	

Dislikes 0	
Response. Thank you for your comment. Requirement R10 responds to FERC directives requiring TOPs to monitor non-BES facilities necessary for determining SOL exceedances. In the rationale for proposed Requirement R10, The SDT included examples of analyses and studies that could lead to the identification of non-BES facilities that should be monitored for determining SOL exceedances. The SDT does not support adding a prescriptive requirement to specify how non-BES facilities should be identified. The time horizon for Requirement R10 is appropriate for monitoring activities. The SDT does not support suggestions to change the testing requirement from 90-days to quarterly. The SDT believes the requirement as written provides clarity and flexibility to determine appropriate times to conduct testing, and that the interval provides reliability benefit by regularly ensuring redundant functionality is maintained.	
Joe Tarantino - 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; - Joe Tarantino	
Answer	No
Document Name	
Comment	
We appreciate the work that the Drafting Team has provided specific to the TOP-001-4 Reliability Standard. However, our concern remains over the test language found in Requirements R21 for the TOP and R24 for the BA. While we understand that monitoring functions do not constitute sufficiency in testing we are concerned that the "test" terminology is subject to interpretation by the responsible entity, auditor, and others that lend itself to inconsistent implementation/auditing of these requirements. To resolve this reliability concern, please clarify the drafting team's intent for the "test" requirement whether this is explicit to each data link or the data link infrastructure or some other intention. We, Sacramento Municipal Utility District and Balancing Authority Northern California, look forward to a resolution from the drafting team on this issue... Thanks.	
Likes 0	

Dislikes 0	
Response. Thank you for your comment. The SDT has provided clarification in the rationale section for the testing requirements to address concerns about what infrastructure needs to be tested. The proposed requirement, with supporting rationale, provide an entity with flexibility to design a testing program to meet operational needs, provide assurance of redundant functionality, and meet the requirement.	
Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

Clark believes that R20 is still not addressing the issue FERC has expressed its concern over. Please read the paragraph in question. In Paragraph 47, Order 817, FERC states:

"We agree with NERC and other commenters that there is a reliability need for the **reliability coordinator, transmission operator and balancing authority to have data exchange capabilities that are redundant and diversely routed**. However, we are concerned that the TOP and IRO Standards do not clearly address redundancy and diverse routing so that **registered entities will unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations**. NERC's comprehensive approach to establishing communications capabilities necessary to maintain reliability in the COM standards is applicable to data exchange capabilities at issue here. Therefore, pursuant to section 215(d)(5) of the FPA, **we direct NERC to modify Reliability Standards TOP-001- 3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing.** In addition, we direct NERC to clarify that "redundant infrastructure" for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities."

The SDT continues to **INCORRECTLY** apply this paragraph first to control centers and now to primary control centers. Paragraph 47 is applicable to the registered the entities RCs, TOPs, and BAs and requires these registered entities to have the referenced redundancy and diverse routing of data exchange. **The terms "control center" or "primary control center" are not used in Paragraph 47**. The SDT continues to fail to recognize that many RCs, TOPs, and BAs already have redundancy and diverse routing of data exchange that addresses the FERC's concerns because they have voluntarily adopted this approach in meeting their COM standards compliance and their EOP-008 compliance.

In Paragraph 48, Order 817, FERC states:

"Further, **we disagree with commenter arguments that Reliability Standard EOP-008-1 provides alternatives to data exchange redundancy and diverse routing**. The NERC standard drafting team that developed the COM standards addressed this issue in the standards development process, responding to a commenter seeking clarification on the relationship between communication capabilities, alternative communication capabilities, primary control center functionality and backup control center functionality. The standard drafting team responded that "Interpersonal Communication and Alternative Interpersonal Communication are not related to EOP-008," even though Reliability Standard EOP-008-1 Requirement R1 applies equally to data communications and voice communications. To the extent the standard drafting team asserted that Reliability Standard EOP-008 did not supplant the redundancy requirements of the COM Reliability Standards, we believe the same is true for data communications. Redundancy for data communications is no less important than the redundancy explicitly required in the COM standards for voice communications."

In Paragraph 48 the FERC **DID NOT state that the use of a backup dispatch center in the provision of alternatives to data exchange redundancy and diverse routing fails to address its concerns expressed in Paragraph 47** . It only stated that the requirement to have such data exchange redundancy and diverse routing is not specifically provided for in EOP-008-1. There is no reason for the SDT to believe that the requirements of Paragraph 47 should be applied to the primary control center. There is every reason to believe that the requirements of Paragraph 47 should be applied to the RCs, TOPs, and BAs provision of reliability data using data exchange capabilities that are redundant and diversely routed.

As such the SDT needs to modify R20 and M20 to the following:

"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. [Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]"

"M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including 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 to perform its Real-time monitoring and Real-time Assessments as specified in the requirement." The above revisions to R20 and M20 will cause Transmission Operators to **"unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations"** which is the concern FERC has expressed. These changes will allow TOPs to submit evidence that the redundant and diversely routed data exchange capabilities being voluntarily used in compliance with the COM standards and EOP-008-1 are also capable of meeting the new MANDATORY requirements of TOP-001-4. The SDT should have no concern that the FERC would reject this since Paragraph 47 clearly **DOES NOT REQUIRE THIS REDUNDANCY AND DIVERSE ROUTING OF DATA EXCHANGE FOR PRIMARY CONTROL CENTERS BUT ONLY FOR RCs, TOPs, and BAs as registered entities.** While Clark is not an RC or a BA, it believes the above arguments are also applicable to these registered entities and that any similar requirements and measures applicable to these entities in IRO-002-5 or TOP-001-4 should be similarly modified.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. In Order No. 817, FERC indicated that requirements for back up control centers in EOP-008 did not "supplant the redundancy requirements" for voice or data communications. The SDT believes the proposed TOP-001-4 Requirements R20 and R23 directly address Order No. 817 directive (P 47) and benefit reliability by assuring TOPs have redundant and diversely routed data exchange capabilities within the primary Control Center. The SDT has discussed their approach with FERC staff observers and believe the approach satisfies the directive.	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
R10.3 states that the TOp must monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator. In the latest revision of the standard, the Standard Drafting Team added language to the Rationale section of the draft standard to clarify that the non-BES facilties that the TOp is required to monitor are "only those that are necessary for the TOp to	

determine SOL exceedances within its Transmissoin Operator Area." While TVA appreciates the additional details in the Rationale section, we feel that the additional details around identification of non-BES facilities belongs in the requirement itself. Compliance obligations are now spreading down below 100 kV facilities into the non-BES system. Whereas there use to be a hard line between where the compliance purview began and stopped, it will now be at times, more ambiguous. For example, now non-BES facilities can be labeled BES facilities or, if this standard passes as written, non-BES facilities will still be non-BES but be required to be monitored if the TOp decides as such. We would prefer to see more clarity in the requirement as to when the TOp would require a non-BES element be monitored. TVA suggests the following language change for the requirement: "R10.3 Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator **in order to determine SOL exceedances on BES elements whithin its Transmission Operator Area.**"	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The suggested addition "in order to determine SOL exceedances within its TOP Area" is covered in the main R10 requirement. The SDT does not agree that the proposed revision provides additional clarity.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
New requirement R20 requires TOPs to have "redundant and diversely routed data exchange infrastructure **within** the Transmission Operator's primary Control Center." R23 contains a similar requirement for BAs to have similar infrastructure "**within** the Balancing Authority's primary Control Center. It has been the ISO's understanding that the concern was with redundancy **into and out** of the Control Center, to and from the outside world. However, the terminology "**within the control center**" could be construed differently that there is some expectation of diversity and redundancy before the data leaves the control center. The ISO requests that the Drafting Team clarify whether or not the intent of this terminology is to apply to routing after the data leaves the Control Center. If indeed the new requirement is meant to apply within the Control Center, the ISO requests that more specificity be provided as to what the	

expectation is for redundancy and diversity (i.e. - Between one operator and another? Between an operator computer and or phone, and the data exchange infrastructure itself?)	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. Proposed requirements for redundant and diversely routed data exchange capabilities apply to infrastructure within the primary Control Center such as switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data. The proposed requirement does not apply to data exchange infrastructure at the point when the data leaves the Control Center.	
Daniel Herring - DTE Energy - Detroit Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Beuthling - Mike Beuthling On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Puscas - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. 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.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
If requirement R10 allows the RC to stipulate non-BES facilities be monitored, 24 months should be allocated to install, test and implement the proper equipment. In addition, if requirements R20 and R23 remain as they are currently worded, such that the TOP and/or BA are required to install redundant and diversely routed data exchange infrastructure within the primary Control Center (only), and do not allow for flexibility for the redundant and diversely routed data exchange infrastructure to span across Control Centers, then APS proposes a minimum of 3 calendar years for implementation.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The TOP is responsible for identifying the non-BES facilities that must be monitored by the TOP for determining SOL exceedances in the TOP's Operating Area. As noted above, the SDT has clarified the rationale for Requirement R10 accordingly. The 12-month implementation period is intended to provide entities with the necessary time to identify their data needs and use the data specification processes in TOP-003-3 to satisfy their data needs. Requirements R20 and R23 will require entities to have redundant and diversely routed data exchange infrastructure in the primary Control Center. The requirements provide entities with flexibility in designing an architecture that precludes single points of failure in the primary Control Center from halting the flow of real-time data to the operator. The SDT believes design principles necessary to achieve this objective are incorporated in primary Control Centers to a large degree, and that entities will not be establishing entirely new alternate data exchange capabilities. A 12-month implementation period is appropriate and responsive to FERC's directive.	

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller	
Answer	No
Document Name	
Comment	
Comments: See comments below.	
Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
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 data identified in TOP-003-3 to monitor non-BES facilities. In that scenario, more time may be needed than what is proposed for Requirement 10.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The 12-month implementation period is intended to provide entities with the necessary time to identify their data needs and use the data specification processes in TOP-003-3 to satisfy their data needs. The SDT believes the requirement provides flexibility for the TOP to determine how to monitor the non-BES facilities that it identifies, and that entities will be able to meet the requirement within the 12-month implementation period.	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy has concerns regarding the effort to achieve compliance with IRO-002-4, and the possible quick turnaround for becoming compliant with IRO-002-5. Entities have already made interpretations, and taken specific actions to achieve compliance with IRO-002-4 prior to it being enforceable in April of 2017. With the potential for such a quick turnaround in standard versions, we believe that delaying the enforcement date for IRO-002-4 until IRO-002-5 is approved and enforceable would be prudent. The delaying of enforcement dates to consolidate versions has happened in the past (see PRC-005). We believe that rolling all changes and enforcement dates to the potential enforcement date for IRO-002-5 is a practical solution for industry stakeholders in achieving compliance with the different versions.

Likes 0	
Dislikes 0	

Response. Thank you for your comment. Revisions in proposed IRO-002-5 address specific directives in Order No. 817 to modify IRO-002-4 to require redundant and diversely routed data exchange capabilities in the RC's primary Control Center, and to test these capabilities for redundant functionality. These objectives are addressed in new requirements in the proposed standard, with minimal change to the approved IRO-002-4 requirements. The SDT does not believe it is necessary to delay implementation of IRO-002-4 from its April 2017 effective date in order to successfully implement the new requirements in IRO-002-5.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Please see comments for Question #1.

Likes 0	
Dislikes 0	
Response. Thank you for your comment. Response provided above.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
We need further guidance on which aspects of our data exchange capability should be redundant in order to answer this question. The old COM-001 was more focused on capabilities outside the Control Center (avoiding the 'backhoe' outages) while this requirement seems to be focused on redundancy within the data center, but ignoring redundancy outside the data center. Additional rigor may need to be added to internal redundancy. Based on that, the 12 month implementation plan may be insufficient. Redundancy and diverse routing in the legacy requirements seemed to mean something different than is being presented in the directive by FERC today.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. Requirements R20 and R23 will require entities to have redundant and diversely routed data exchange infrastructure in the primary Control Center. The requirements provide entities with flexibility in designing an architecture that precludes single points of failure in the primary Control Center from halting the flow of real-time data to the operator. The SDT believes design principles necessary to achieve this objective are incorporated in primary Control Centers to a large degree, and that entities will not be establishing entirely new alternate data exchange capabilities. A 12-month implementation period is appropriate and responsive to FERC's directive.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	

Comment	
We thank the SDT for providing clarity that the scope of the requirements are aimed at the applicable entity's primary Control Center. However, we disagree with the SDT that entities will have sufficient time with a 12-month implementation plan. That assumption is based on TOPs and BAs already have adequate infrastructure and data exchange capabilities in place to perform their SOL exceedance determinations, monitoring, and assessment calculations. We believe there is a possibility that they won't, particularly with owners of non-BES facilities that are identified as necessary for TOPs and BAs to complete their functional obligations. In this instance, TOPs and BAs could be faced with a compliance-based decision to either sacrifice reliability concerns by identifying these facilities as not necessary for monitoring and assessments or identify, procure, install, and continue to maintain adequate infrastructure and data exchange capabilitibities with these facilities in order to remain compliant. In the latter instance, incurring such costs could be done outside budgeting approvals for smaller entities, particularly in a compressed 12-month implementation period. We propose a 24-month implementation period instead, as that could accommodate 2-3 possible budget cycles.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The 12-month implementation period is intended to provide entities with the necessary time to identify their data needs and use the data specification processes in TOP-003-3 to satisfy their data needs. The SDT believes the requirement provides flexibility for the TOP to determine how to monitor the non-BES facilities that it identifies, and that entities will be able to meet the requirement within the 12-month implementation period.	
Douglas Webb - 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; - Douglas Webb	
Answer	No
Document Name	
Comment	
No.	

The proposed Implementation Plan does not consider the time required to meld the technology required to address compliance under TOP-001-4 R10 and compliance under CIP-002-5.1. The period should be extended by a year.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The additional requirement for TOPs to monitor non-BES facilities identified by the TOP as necessary for determining SOL exceedances is not impacted by categorization required by CIP-002-5.1.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
No - TOP-001-4 No - IRO-002-5	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
: No concerns with the timelines proposed with implementation assumed 4/1/2018 based on current schedule.	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE appreciates the SDT's inclusion of an "Initial Performance of Periodic Requirements" section. Texas RE believes that this is a best practice and recommends that future SDTs provide a similar section for all periodic requirements to avoid ambiguity. Texas RE does not necessarily object to the SDT's proposed 12-month implementation period. However, Texas RE respectfully requests that the SDT provide a basis for its decision to adopt such a 12-month compliance window, including any data it considered in determining that this was an appropriate window for affected entities to meet their compliance obligations under the revised Standards.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The SDT developed the implementation periods based on their experience and with consideration of stakeholder comments during the standards development process. The 12-month implementation period for TOP-001-4 provides Transmission Operators (TOP) with time to revise and distribute data specifications required by TOP-003-3 Requirement R1 to include non-BES data identified by the TOP, and receive data from entities responsible for providing the data as required by TOP-003-3 Requirement R5. The implementation period also provides TOPs and Balancing Authorities (BAs) with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality.	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Michael Puscas - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - 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; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no National Grid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Beuthling - Mike Beuthling On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Lyons - Owensboro Municipal Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. 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.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
(1) We thank the SDT for responding to our request to account for the "as necessary" parts of requirement R10 within the VSLs. (2) However, we believe the SDT has an opportunity to develop more performance-based requirements for these standards. We believe the VSLs for these requirements should base compliance on a definite period of time that has lapsed when a registered entity is unable to perform its monitoring functions or conduct its assessments. This scalable time duration could then be used to identify VSLs for the complete set, and not just values for Severe VSLs. We propose an exceedance of 30 minutes listed as a Low VSL, with a 30-minute increment for each increasing severity limit.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The SDT believes that the VSL construct in approved TOP-001-3 benefits reliability and did not need to be modified to address the directives in Order No. 817.	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	

As proposed, the VRFs and VSLs treat each R10 sub requirement equally when in reality both the risk and resulting potential impact is significantly different between the requirements. The risk and associated potential impact of a TOP not monitoring it's own Facilities and RAS's is significantly greater on the ability for state estimation and contingency analysis to solve and provide accurate results than to not monitor non-BES facilities within it's system or external TOP areas' Facilities/RAS's/non-BES facilities.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The SDT believes that it is important to monitor all of the items described in sub-parts since they are necessary for determining SOL exceedances. Entities may be able to determine which facilities have more impact, but a more prescriptive VSL may not be accurate for all entities and systems.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Please see comments for Question #1.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. See response above.	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller	
Answer	No
Document Name	
Comment	

Comments: See comments below.	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - 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; - Joe Tarantino	
Answer	No
Document Name	
Comment	
We are concerned over the issue raised for "test" in TOP-001-4 Requirements R21 & R24 pertaining to the lack of clarity for implementation and audit approach and therefor cannot agree with and VRF/VSL associated with these requirements.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. As stated above, the SDT has provided clarification to the rationale section for the testing requirement to address concerns about what infrastructure needs to be tested.	
Michael Puscas - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	

The language for the NERC Standard, IRO-002-5, R3, Severe VSL. The last paragraph states: The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once each every 90 calendar month days but, following an unsuccessful test, did not initiate action to restore the redundant functionality in more than 8 hours.

This does not convey the intent. Literally, it says that the violation occurred because the action was initiated in 8 hours or less or that there were 8 or fewer hours in which actions were initiated. I'd suggest changing the language to:

The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once each every 90 calendar month days but, following an unsuccessful test, did not initiate action to restore the redundant functionality within 8 hours of the test failure.

Likes 0	
Dislikes 0	

Response. Thank you for your comment. The Severe VSLs for the testing requirements in IRO-002-5 and TOP-001-4 have been revised to address this issue.

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

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

Answer	Yes

Document Name	
Comment	
They seem consistent based on the requirements as stated. If the periodicity changes to 'quarterly' the VRF's and VSL's would need to change accordingly	
Likes 0	
Dislikes 0	
Response. Thank you for your comment.	
Thomas Lyons - Owensboro Municipal Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Douglas Webb - 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; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerome Gobby - Sempra - San Diego Gas and Electric - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Beuthling - Mike Beuthling On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Mike Beuthling	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no National Grid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	
Document Name	
Comment	
No - TOP-001-4 No - IRO-002-5	
Likes 0	
Dislikes 0	
Response	

5. Provide any additional comments for the SDT to consider, if desired.	
Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

Clark believes that R21 is still not addressing the issue FERC has expressed its concern over. Please read the paragraph in question. In Paragraph 51, Order 817, FERC states:

"We agree with NERC and other commenters that there is a reliability need for the reliability coordinator, transmission operator and balancing authority to test alternate data exchange capabilities. However, we are not persuaded by the commenters' assertions that the need to test is implied in the TOP and IRO Standards. Rather, we determine that testing of alternative data exchange capabilities is important to reliability and should not be left to what may or may not be implied in the standards. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to **develop a modification to the TOP and IRO standards that 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.** 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."

The only reference to the primary control center in Paragraph 51 is that the overall data exchange capabilities needs to be tested to ensure that "**the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority" are tested.** If the exchange capabilities used in the primary control centers are the **primary or most frequently used data exchange capabilities**, it is obvious that some other alternate data exchange is the scope of the FERC's directive. This may be and alternate data exchange capability in the primary control center but there is nothing in Paragraph 51 that would preclude the use of a backup control center for the provision of the alternate or less frequently used data exchange capabilities. The SDT continues to INCORRECTLY apply this paragraph first to control centers and now to primary control centers. Paragraph 51 is applicable to the registered the entities RCs, TOPs, and BAs and requires these registered entities to **test the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority.** The SDT continues to fail to recognize that many RCs, TOPs, and BAs already have redundancy and diverse routing of data exchange that addresses the FERC's concerns because they have voluntarily adopted this approach in meeting their COM standards compliance and their EOP-008 compliance. For these entities, testing the alternate data exchange capabilities of their backup control centers would address the FERC's concerns expressed in Paragraph 51.

As such the SDT needs to modify R21 and M21 to the following:

"R21. Each Transmission Operator shall test its alternate or less frequently used data exchange capabilities specified in Requirement R20 for redundant functionality at least once each every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]"

"M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its alternate or less frequently used data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications."

The above revisions to R21 and M21 will cause Transmission Operators to test their alternate or less frequently used data exchange capabilities specified in Requirement R20 every 90 calendar days which is the concern FERC has expressed. These changes will allow TOPs to submit evidence that the alternate or less frequently used data exchange capabilities being voluntarily used in compliance with the COM standards and EOP-008-1 have been tested to demonstrate redundant functionality (as well as alternate or less frequently use data exchage capabilities at the primary control center). The SDT should have no concern that the FERC would reject this since Paragraph 51 clearly ONLY REQUIRES THE TESTING OF THE ALTERNATE OR LESS FREQUENTLY USED DATA EXCHANGE CAPABILITIES OF THE RCs, TOPs, and BAs (regardless of the location).

While Clark is not an RC or a BA, it believes the above arguments are also applicable to these registered entities and that any similar requirements and measures applicable to these entities in IRO-002-5 or TOP-001-4 should be similarly modified.

Likes 0	
Dislikes 0	

Response. Thank you for your comment. In Order No. 817, FERC indicated that requirements for back up control centers in EOP-008 did not "supplant the redundancy requirements" for voice or data communications. The SDT believes the proposed TOP-001-4 Requirements R20, 21 and R23, R24 directly address Order No. 817 directive (P 47, P 51) and benefit reliability by assuring TOPs and BAs have redundant and diversely routed data exchange capabilities within the primary Control Center and that these redundant capabilities are periodically tested. The SDT has discussed their approach with FERC staff observers and believe the approach satisfies the directives.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
(1) We thank the SDT for its detailed information included in the standards' rationale boxes, as such information is useful in understanding the purpose and intent of each requirement. However, we caution that each requirement must be clear and understandable by both registered entities and auditors to demonstrate and measure compliance, respectively. We recommend incorporating aspects of these rationale boxes, within the language of each requirement, where possible. (2) We thank the SDT for this opportunity to provide comments on these standards.	
Likes 0	
Dislikes 0	
Response. Thank you for your comments. The SDT focused on developing results-based requirements that avoid prescribing specific approaches to meet the reliability objectives. Rationale boxes provide examples and other details that illustrate the drafting team's intent. The information in the rationale boxes is retained in the Guidelines section of the approved standards and has been included in the draft RSAWs.	
Joe Tarantino - 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; - Joe Tarantino	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joshua Smith - Joshua Smith On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Joshua Smith	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawna Speer - Colorado Springs Utilities - 1, Group Name Colorado Springs Utilities	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Puscas - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Thanks for all your work.	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

ATC agrees with the following comments put forth by NSRF.

Suggestions for the Rationale box for R20/R23:

For the paragraph that reads "The reliability objective of redundancy is to provide…." The current wording is not clear for the last sentence of the paragraph. The NSRF recommends that the last sentence of that paragraph be changed to read "For periods of planned or unplanned outages of individual components in the primary or redundant data exchange path, the requirements do not require additional data exchange infrastructure or components during those planned and unplanned outage periods".

The NSRF would like to point out the FERC Order 693, section 253 states that "…compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement…". Within TOP-001-4 there are Rational boxes (e.g. R23) that explain in detail

what Redundant and Diversely routed **MAY** mean. Without these details being within the Requirement, "Redundant and diversely routed" become ambiguous words that will allow an Entity to believe they mean one thing and an auditor may believe in something else. The NSRF recommends that the details written in the Rational box be prefaced with "Some examples of Redundant and diversely routed may mean … depending on how the responsible entity wishes to address their Redundant and diversely routed risks within their Primary Control Center".	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The SDT has revised the wording or the rationale boxes for R20 and R23 to clarify applicability during planned or unplanned outages. The SDT does not believe further revisions to the rationale boxes to address FERC Order 693 P 253 are needed.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	

For R9, the focus on this comment is based on how this relates to EMS, SCADA and associated control systems. WAPA would contend that switching to a redundant host (server, system, computer, etc) that provides functionally equivalent service, that this would not fall under the banner of a "planned outage". If an entity were to not have functionally equivalent redundant hosts and perform a switch-over, this would fall under the planned or unplanned outage banner. WAPA would like to get clarification on this as to plan appropriately for its process to meet the new standard verbiage.

Likes 0	
Dislikes 0	

Response. Thank you for your comment. Requirement R9 is not in scope for Project 2016-01.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

While ERCOT recognizes that the SDT added the word "primary" to further specify which control center is required to include redundant and diversely routed data exchange capabilities, ERCOT requests further clarification on the term "primary Control Center." While it can reasonably be assumed that "primary Control Center" is intended to refer to the Control Center normally used for daily, non-emergency "monitoring and control of the BES in real-time" rather than a Control Center normally used as a backup, this understanding should be explicitly stated to avoid any question as to the breadth of the standard's scope.

ERCOT asks for this clarification to ensure that a backup control center is not considered a "primary" control center during those temporary conditions in which a failover to the backup is required. If an entity lacks redundant or diversely routed data exchange capabilities at a backup control center that may temporarily function as a "primary control center" for a brief period of time, auditors might deem the entity to be out of compliance for that duration. ERCOT therefore recommends defining the term "primary Control Center" in the standard or in the NERC Glossary of Terms, as opposed to simply providing clarification in the rationale or measure, so that the clarification is more clearly enforceable.

ERCOT notes that several other standards use the term "primary control center," including EOP-008-1 – Loss of Control Center Functionality, and CIP-014-2 – Physical Security. In CIP-014-2, the "Guidelines and Technical Basis" section states that the primary control center is “the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation…” ERCOT suggests that a definition similar to that used in CIP-014-2 could provide the needed clarification.

100% Redundancy and Diversity Compliance at all times

As currently written, Requirement R2 of IRO-002-5 and requirement R23 of TOP-001-4, could still be read to require 100% system integrity at all times, no matter what events or failures may arise in an entity’s data exchange capabilities that could, for a time, cause the system to lack redundancy or diverse routing.

Is an entity out of compliance with these requirements if it has redundancy built into its system and, for the majority of the time, functions properly, but temporarily fails during a broader system failure? Would an entity be considered non-compliant because the redundancy is temporarily unavailable?

While the SDT sought to address this concern by adding language to the rationale box and pointed to measure language regarding evidence, neither the rationale nor the measure is enforceable. ERCOT therefore recommends adding the phrase “during normal system conditions” or “during normal system operations” to the identified requirements to clarify that entities are not required to have “additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.”

Additionally, the SDT may wish to consider language similar to that used in EOP-008, R3:

“To avoid requiring tertiary functionality, backup functionality is not required during:

• Planned outages of the primary or backup functionality of two weeks or less

• Unplanned outages of the primary or backup functionality”

Likes 0	
Dislikes 0	

Response. Thank you for your comment. The SDT agrees that the primary Control Center refers to an entity's normal Control Center used for real-time monitoring and control of the BES and is distinguished from the back-up control center required by EOP-008. The SDT's intent is to establish clear requirements for this control center to have redundant and diversely routed data exchange capabilities in response to FERC Order No. 817 directives. The SDT believes that the proposed requirements, with supporting details included in the rationale provide entities with the necessary clarity and flexibility to meet this reliability objective. A prescriptive definition could impact this flexibility or have undesired consequences for approved standards. Proposed TOP-001-4 and IRO-002-5 are not intended to consider or imply that a back-up control center would become a primary control center at some point in time.

The SDT believes the rationale and Measures addresses the concern with compliance during outages of data exchange infrastructure components. The rationale remains in the supplemental material section of the standard, once approved. Further, IRO-002-5 Measure M2 and TOP-001-4 Measures M20 and M23 is drafted to support the SDT's intent for Requirement R20. The associated measure specifies that the evidence of compliance includes documentation listing data exchange capabilities, system diagrams, and system specifications. The SDT does not believe the suggested wording for the requirements adds clarity. The SDT considered wording used in EOP-008 but did not support the approach because it could limit how an entity achieves redundant functionality.

Douglas Webb - 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; - Douglas Webb

Answer	Yes
Document Name	

Comment

Kansas City Power and Light Company greatly appreciates the work of the Standard Drafting Team. Thank you.

Likes 0	
Dislikes 0	

Response

Thomas Lyons - Owensboro Municipal Utilities - 3

Answer	Yes

Document Name	
Comment	

We continuously monitor our system and the assessment provides no benefit just additional administrative work.

Likes 0	
Dislikes 0	

Response. Thank you for your comment.

Scott McGough - Georgia System Operations Corporation - 3

Answer	
Document Name	
Comment	

For IRO-002-5

Comments: Southern believes that the language in IRO-002-5 R2 explicitly limits the scope of the requirement to "the data exchange infrastructure inside the Primary Control Center". The first problem here is that the term "data exchange infrastructure" has no clear or broadly accepted industry definition.

The second problem is that here is no clear definition of what constitutes the control center. Is it a facility or a room inside a facility? What prevents someone from moving the "capability" outside the control center (i.e a data center not part of the control center)?

The language in IRO-002-5 R3 currently has a requirement to test the "primary control center data exchange capabilities" specified in R2" every 90 days. First of all, the terminology shifts from the word "infrastructure" in R2 to "capabilities" in R3, which leaves a lot of ambiguity. Why establish a requirement to test the redundancy of the data exchange and not the EMS platform in which the capability resides. This is perplexing given the fact that the data exchange function is, in most cases, a sub-component of the much larger distributed EMS architecture.

The language in IRO-002-5 R6 is also confusing, as it states that "each RC shall have monitoring systems that provide information utilized by the RC's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and

synchronized information systems, over a redundant infrastructure. Again, this is very confusing, because the following questions have not been answered: • What is meant by "particular emphasis"? • Which "awareness systems" require redundant infrastructure • Which "automated data transfers" are in scope? • Which "synchronized information" is in scope? • What level of redundancy is required? Server level, component level, network level, etc.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The SDT has provided details in the rationale box to clarify the SDT's intent for data exchange infrastructure covered by the proposed requirements. The SDT uses the defined term Control Center in the proposed requirements, which includes associated data center(s) in the definition. The SDT is responding to specific directives in Order No. 817 pertaining to data exchange capabilities. The SDT believes proposed IRO-002-5 Requirements R2 and R3 meet the directive and are beneficial to reliability without expansion to cover redundancy in EMS. The SDT has not made changes to Requirement R6 (Requirement R4 in approved IRO-002-4) in addressing the directives. Requirement R6 is not in scope for Project 2016-01.	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller	
Answer	
Document Name	
Comment	
Comments: Southern believes that the language in IRO-002-5 R2 explicitly limits the scope of the requirement to "the data exchange infrastructure inside the Primary Control Center". The first problem here is that the term "data exchange infrastructure" has no clear or broadly accepted industry definition. The second problem is that here is no clear definition of what constitutes the control center. Is it a	

facility or a room inside a facility? What prevents someone from moving the "capability" outside the control center (i.e a data center not part of the control center)? The language in IRO-002-5 R3 currently has a requirement to test the "primary control center data exchange capabilities" specified in R2" every 90 days. First of all, the terminology shifts from the word "infrastructure" in R2 to "capabilities" in R3, which leaves a lot of ambiguity. Why establish a requirement to test the redundancy of the data exchange and not the EMS platform in which the capability resides. This is perplexing given the fact that the data exchange function is, in most cases, a sub-component of the much larger distributed EMS architecture. The language in IRO-002-5 R6 is also confusing, as it states that "each RC shall have monitoring systems that provide information utilized by the RC's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. Again, this is very confusing, because the following questions have not been answered: • What level of redundancy is required? Server level, component level, network level, etc. • Which "synchronized information" is in scope? • Which "automated data transfers" are in scope? • Which "awareness systems" require redundant infrastructure • What is meant by "particular emphasis"?	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The SDT has provided details in the rationale box to clarify the SDT's intent for data exchange infrastructure covered by the proposed requirements. The SDT uses the defined term Control Center in the proposed requirements, which includes associated data center(s) in the definition. The SDT is responding to specific directives in Order No. 817 pertaining to data exchange capabilities. The SDT believes proposed IRO-002-5 Requirements R2 and R3 meet the directive and are beneficial to reliability without expansion to cover redundancy in EMS.	

The SDT has not made changes to Requirement R6 (Requirement R4 in approved IRO-002-4) in addressing the directives. Requirement R6 is not in scope for Project 2016-01.	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
The NSRF would like to point out that there is a great deal of compliance information in the newly updated Rationale Boxes. We agree this gives insight to meeting the task(s) assigned to each Requirement, but does not allow for clear understanding to the applicable Entity and CEA Staff. FERC Order 693, Section 253 states that applicable Entities must meet the word of the Requirement in order to show that they are Compliant with said Requirement. The NSRF recommends that the intent of the Rationale Box be within each Requirement.	
Likes 0	
Dislikes 0	
Response. Thank you for your comment. The SDT focused on developing results-based requirements that avoid prescribing specific approaches to meet the reliability objectives. Rationale boxes provide examples and other details that illustrate the drafting team's intent. The information in the rationale boxes is retained in the Guidelines section of the approved standards and has been included in the draft RSAWs.	
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	
Response	

End of Report

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016
45-day formal comment period with ballot	June 20 - August 3, 2016
45-day formal comment period with additional ballot	August 31 - October 17, 2016

Anticipated Actions	Date
10-day final ballot	December 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**

2. **Number:** IRO-002-5

3. **Purpose:** To provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinators

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirements R1 and R2: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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) primary 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. 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.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the RC's primary Control Center is not addressed by the proposed requirement.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

Rationale for Requirement R3: The revised requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R3. Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R3. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

R5. Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R4 and Measures M1, M2, and M4.
- The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 and Measures M5 and M6 for the current calendar year and one previous calendar year.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2.	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, as specified in the requirement.	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.
R3.	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	capabilities specified in Requirement R2 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Reliability Coordinator did not test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				maintenance of its telecommunication, monitoring and analysis capabilities.
R5.	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6.	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	FERC approval
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:

The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:

Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 (R6 in IRO-002-5) has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for R4 (R6 in IRO-002-5):

The requirement was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016
45-day formal comment period with ballot	June 20 - August 3, 2016
45-day formal comment period with additional ballot	August 31 - October 17, 2016

Anticipated Actions	Date
~~45-day formal comment period with additional ballot~~	~~September 2016~~
10-day final ballot	~~November~~ December 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-5
3. **Purpose:** To provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirements R1 and R2: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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) primary 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. 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.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, ~~The~~ the proposed requirements do not ~~specify~~ require additional redundant data exchange infrastructure components solely to provide for redundancy. ~~during planned or unplanned outages of individual components.~~

Infrastructure that is not within the RC's primary Control Center is not addressed by the proposed requirement.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

Rationale for Requirement R3: The revised requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R3. Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R3. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

R5. Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R4 and Measures M1, M2, and M4.
- The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 and Measures M5 and M6 for the current calendar year and one previous calendar year.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2.	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, as specified in the requirement.	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.
R3.	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	capabilities specified in Requirement R2 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Reliability Coordinator did not test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality ~~in more than 8 hours~~.
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
R5.	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6.	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	FERC approval
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:

The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:

Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 (R6 in IRO-002-5) has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for R4 (R6 in IRO-002-5):

The requirement was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-~~4~~5
3. **Purpose:** To ~~Provide~~ provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability**

4.1. Functional Entities

~~4.1.~~4.1.1 Reliability Coordinator

5. **Effective Date:**

See Implementation Plan~~.~~

~~**6. Background:**~~

~~See the Project 2014~~2016-~~03~~ 01.

B. Requirements and Measures

Rationale for Requirements R1 and R2: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47). Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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) primary 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. 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. The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the RC's primary Control Center is not addressed by the proposed requirement.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments~~. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its ~~operational~~ Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments~~.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other~~a~~ documentation that lists its data exchange capabilities, ~~with~~including redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

Rationale for Requirement R3: The revised requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R3. Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~every 90 calendar ~~month~~days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality,~~;~~ or experienced an event that demonstrated the redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R3. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

~~R2.~~R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

~~M1.~~M4. Each Reliability Coordinator shall, have and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

~~R3.~~R5. Each Reliability Coordinator shall monitor Facilities, the status of ~~Special Protection System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any ~~-~~System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of ~~Special Protection System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

~~R4.~~R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~**1.2. Compliance Monitoring and Assessment Processes:**~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~1.2. ~~Data~~ Evidence Retention

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

~~The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and ~~R3~~R4 and Measures M1, M2, and ~~M3~~M4.

The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 ~~R4~~ and Measures M5 and M6 ~~M4~~ for the current calendar year and one previous calendar year.

~~If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.~~

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~1.4. Additional Compliance Information~~

~~None.~~

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, as specified in the requirement.	
R3	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Reliability Coordinator did not test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality ~~at least once each calendar month~~; OR The Reliability Coordinator tested its primary Control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
~~R2~~R4	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
~~R3~~R5	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of ~~Special Protection~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
~~R4~~R6	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The Implementation Plan and other project documents can be found on the project page.~~None.~~

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised

3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	FERC approval
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

~~**Rationale:**~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:

The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The ~~SDT~~Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:

Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 (R6 in IRO-002-5) has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for R4 (R6 in IRO-002-6):

The ~~R~~requirement ~~R4~~ ~~R6~~ was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016
45-day formal comment period with ballot	June 20 - August 3, 2016
45-day formal comment period with additional ballot	August 31 - October 17, 2016

Anticipated Actions	Date
10-day final ballot	December 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Transmission Operations**
2. **Number:** TOP-001-4
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.2. Transmission Operator

   4.1.3. Generator Operator

   4.1.4. Distribution Provider

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the

Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not

limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

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 Transmission Operator 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 the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area

and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_V. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a

SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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 Transmission Operator's (TOP) primary 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. 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'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. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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 to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Rationale for Requirements R22 and R23: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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 Balancing Authority's (BA) primary 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. Requirement R23 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 BA'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. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

R22. Each Balancing Authority shall have data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M22. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 to perform its Real-time monitoring and analysis functions as specified in the requirement.

Rationale for Requirement R24: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component(e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.

- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.
- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R19, and Measure M15 through M19 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep data or evidence for Requirement R22 and Measure M22 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items	The Transmission Operator did not monitor, obtain, or utilize two of the items required or	The Transmission Operator did not monitor, obtain, or utilize three of the items required or	The Transmission Operator did not monitor, obtain, or utilize four or more of the items

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.
R11	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Center, as specified in the Requirement.	
R21	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				restore the redundant functionality.
R22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, as specified in the Requirement.	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.
R24	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test;

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is:
http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Rationale for Requirement R3:

The phrase ‘cannot be physically implemented’ means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator’s Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016
45-day formal comment period with ballot	June 20 - August 3, 2016
45-day formal comment period with additional ballot	August 31 - October 17, 2016

Anticipated Actions	Date
~~45-day formal comment period with additional ballot~~	~~September 2016~~
10-day final ballot	~~November~~ December 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Transmission Operations**
2. **Number:** TOP-001-4
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
     - **4.1.2.** Transmission Operator
     - **4.1.3.** Generator Operator
     - **4.1.4.** Distribution Provider
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the

Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not

limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

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 Transmission Operator 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 the TOP to ~~the identification~~ identify ~~of~~ a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area

and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_V. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a

SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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 Transmission Operator's (TOP) primary 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. 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'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. For periods of planned or unplanned outages of individual data exchange components, the~~The~~ proposed requirements do not ~~specify~~ require additional redundant data exchange infrastructure components solely to provide for redundancy~~ during planned or unplanned outages of individual components~~.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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 to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Rationale for Requirements R22 and R23: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

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 Balancing Authority's (BA) primary 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. Requirement R23 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 BA'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. For periods of planned or unplanned outages of individual data exchange components, the ~~The~~ proposed requirements do not ~~specify~~ require additional redundant data exchange infrastructure components solely to provide for redundancy ~~during planned or unplanned outages of individual components~~.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

R22. Each Balancing Authority shall have data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M22. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 to perform its Real-time monitoring and analysis functions as specified in the requirement.

Rationale for Requirement R24: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component(e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.
- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through ~~R20~~R19, and Measure M15 through ~~M20~~ M19 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall ~~each~~ keep data or evidence for ~~each applicable~~ Requirement R22 ~~through R23,~~ and Measure M22 ~~through M23~~ for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items	The Transmission Operator did not monitor, obtain, or utilize two of the items required or	The Transmission Operator did not monitor, obtain, or utilize three of the items required or	The Transmission Operator did not monitor, obtain, or utilize four or more of the items

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.
R11	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Center, as specified in the Requirement.	
R21	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate~~d~~ action within 8 hours to restore the redundant

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				functionality ~~in more than 8 hours~~.
R22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, as specified in the Requirement.	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.
R24	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test;

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate~~d~~ action within 8 hours to restore the redundant functionality ~~in more than 8 hours~~.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is:
http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

A. Introduction

1. **Title: Transmission Operations**

2. **Number: TOP-001-~~3~~4**

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

5. **Effective Date:**

   See Implementation Plan~~.~~

~~6. **Background:**~~

~~See Project 2014-03 project page.~~

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

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

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and

provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

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

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings,

electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

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 Transmission Operator 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 the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

R10. Each Transmission Operator shall perform the following ~~as necessary~~ for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. ~~Within its Transmission Operator Area, monitor~~ Monitor Facilities within its Transmission Operator Area; ~~and~~

10.2. Monitor the status of ~~Special Protection Systems~~Remedial Action Schemes within its Transmission Operator Area;

~~**10.1.**~~**10.3.** Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;~~and~~

10.4. ~~Outside its Transmission Operator Area, o~~Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

~~**10.2.** and the status of Special Protection Systems.~~

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized ~~status, voltages, and flow~~ data ~~for Facilities and the status of~~

~~Special Protection Systems~~ as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

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

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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 Transmission Operator's (TOP) primary 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. 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'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. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses.~~the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.~~ *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Transmission Operator Area~~perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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]

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary 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 to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Rationale for Requirements R22 and R23: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, 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 Balancing Authority's (BA) primary 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. Requirement R23 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 BA'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. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy. Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

~~R20.~~R22. Each Balancing Authority shall have data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to develop its Operating Plan for next-day operations.~~maintain reliability in its Balancing Authority Area.~~ *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M22~~0~~. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Balancing Authority Area~~develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, 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 to perform its Real-time monitoring and analysis functions as specified in the requirement.

Rationale for Requirement R24: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~As defined in the NERC Rules of Procedure,~~ "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable ~~the NERC~~ Reliability Standards in their respective jurisdictions.

~~**1.2. Compliance Monitoring and Assessment Processes**~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~1.2. ~~Data~~ Evidence Retention

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. 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 the full time period since the last audit.~~

Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and ~~R15 through R20 and~~ Measure M1 through M11~~, and M15 through M20~~ for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ~~ninety~~ 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.

~~and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.~~

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

Each Transmission Operator shall retain evidence ~~and~~ that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.

Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R19, and Measure M15 through M19 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.

Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Balancing Authority shall keep data or evidence for Requirement R22 and Measure M22 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.

Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

~~If a Balancing Authority, Transmission Operator, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.~~

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~**1.4. Additional Compliance Information**~~

~~None.~~

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities,	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Emergency on respective Balancing Authority Areas.	resulted in, an Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.~~N/A~~	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1~~.~~ through 10.6. ~~OR,~~ ~~The Transmission Operator did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.~~	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6 ~~and did not obtain and utilize one of the items listed in Requirement R10, Part 10.2~~.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.~~Facilities and the status of Special Protection Systems within its Transmission Operator Area and did not obtain and utilize data deemed as necessary from outside its Transmission Operator Area.~~
R11	N/A	N/A	The Balancing Authority did not monitor the status of ~~Special Protection System~~Remedial Action Schemes that impact	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	support Interconnection frequency.
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, as specified in the Requirement.	
R21	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality; OR The Transmission Operator tested its primary Control Center data exchange

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
~~R20~~R 22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange	The Balancing Authority did not have data exchange

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, as specified in the Requirement.	capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.
R24	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test;	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The ~~SDT~~Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

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Implementation Plan

Project 2016-01 Modifications to TOP and IRO Standards
Reliability Standards IRO-002-5 and TOP-001-4

Applicable Standard(s)

- IRO-002-5 - Reliability Coordination - Monitoring and Analysis
- TOP-001-4 - Transmission Operations

Requested Retirement(s)

- IRO-002-4 - Reliability Coordination - Monitoring and Analysis
- TOP-001-3 - Transmission Operations

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

On November 19, 2015, the Federal Energy Regulatory Commission (FERC) issued Order No. 817 approving nine revised or new TOP and IRO Reliability Standards from Project 2014-03 that addressed previously-identified reliability issues and concerns. In approving the standards, FERC also directed development of modifications to TOP and IRO standards to address specific concerns related to: (i) Transmission Operator monitoring of some non-Bulk Electric System (non-BES) elements needed for reliable operations, and (ii) redundancy in data exchange capabilities used by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable operations.

General Considerations

The three-month implementation period for IRO-002-5 provides Reliability Coordinators with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality. The proposed implementation plan presumes that IRO-002-4 is effective, or will become effective, on or before the effective date of IRO-002-5.

The 12-month implementation period for TOP-001-4 provides Transmission Operators (TOP) with time to revise and distribute data specifications required by TOP-003-3 Requirement R1 to include non-BES data identified by the TOP, and receive data from entities responsible for providing the data as required by TOP-003-3 Requirement R5. The implementation period also provides TOPs and Balancing Authorities (BAs) with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality.

Effective Date

IRO-002-5

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-001-4

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

IRO-002-4

Reliability Standard IRO-002-4 shall be retired immediately prior to the effective date of IRO-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

TOP-001-3

Reliability Standard TOP-001-3 shall be retired immediately prior to the effective date of TOP-001-4 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

IRO-002-5
The initial test of primary Control Center data exchange capabilities specified in Requirement R3 must be completed within 90 calendar days of the effective date of IRO-002-5.

TOP-001-4
The initial test of primary Control Center data exchange capabilities specified in Requirements R21 and R24 must be completed within 90 calendar days of the effective date of TOP-001-4.

Implementation Plan

Project 2016-01 Modifications to TOP and IRO Standards
Reliability Standards IRO-002-5 and TOP-001-4

Applicable Standard(s)

- IRO-002-5 - Reliability Coordination - Monitoring and Analysis
- TOP-001-4 - Transmission Operations

Requested Retirement(s)

- IRO-002-4 - Reliability Coordination - Monitoring and Analysis
- TOP-001-3 - Transmission Operations

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

On November 19, 2015, the Federal Energy Regulatory Commission (FERC) issued Order No. 817 approving nine revised or new TOP and IRO Reliability Standards from Project 2014-03 that addressed previously-identified reliability issues and concerns. In approving the standards, FERC also directed development of modifications to TOP and IRO standards to address specific concerns related to: (i) Transmission Operator monitoring of some non-Bulk Electric System (non-BES) elements needed for reliable operations, and (ii) redundancy in data exchange capabilities used by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable operations.

General Considerations

The three-month implementation period for IRO-002-5 provides Reliability Coordinators with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality. The proposed implementation plan presumes that IRO-002-4 is effective, or will become effective, on or before the effective date of IRO-002-5.

The 12-month implementation period for TOP-001-4 provides Transmission Operators (TOP) with time to revise and distribute data specifications required by TOP-003-3 Requirement R1 to include non-BES data identified by the TOP, and receive data from entities responsible for providing the data as required by TOP-003-3 Requirement R5. The implementation period also provides TOPs and Balancing Authorities (BAs) with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality.

Effective Date

IRO-002-5

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-001-4

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

IRO-002-4

Reliability Standard IRO-002-4 shall be retired immediately prior to the effective date of IRO-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

TOP-001-3

Reliability Standard TOP-001-3 shall be retired immediately prior to the effective date of TOP-001-4 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

IRO-002-5
The initial test of primary Control Center data exchange capabilities specified in Requirement R3 must be completed within 90 calendar days of the effective date of IRO-002-5.

TOP-001-4
The initial test of primary Control Center data exchange capabilities specified in Requirements R21 and R24 must be completed within 90 calendar days of the effective date of TOP-001-4.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2016-01 - Modifications to TOP and IRO Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Reliability Standard requirements developed in Project 2016-01. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. 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.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance
Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties
A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement
VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

Project 2016-01 Reliability Standards Requirements

The SDT developed new or revised requirements in IRO-002-5 and TOP-001-4 to address reliability objectives outlined in the project Standard Authorization Request (SAR). The VRF and VSL justification for these new and revised requirements is described below. VRF and VSL justification for requirements that were not modified in Project 2016-01 can be found on the Project 2014-03 Project Page.

VRF Justification

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirement is not directly connected to an area identified in the Blackout Report.

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The proposed VRF is unchanged from approved TOP-001-3 Requirement R10. Additionally, the requirement is similar to approved IRO-002-4 Requirement R3 which applies to Reliability Coordinators and is assigned a High VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement addresses a single reliability objective and has a single VRF.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Operations Planning time horizon, which are not the subject of the Blackout Report recommendations regarding data exchange. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements address data exchange capabilities for the Operations Planning time horizon only, which is a significant change from approved IRO-002-4 Requirement R1 and TOP-001-3 Requirements R19 and R20 which apply to all operations time horizons. As proposed, the VRF will establish consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a Medium VRF. Failure to have data exchange capabilities necessary for performing Operational Planning Analysis or for developing an Operating Plan for next day operations could directly and adversely affect the electrical state or capability of the BES, or the ability to effectively control or restore the BES. However, this failure is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Same-day Operations and Real-time Operations time horizons. A High VSL is assigned to reflect the potential impact on the reliability of the BES consistent with the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements improve upon requirements for data exchange capabilities in approved IRO-002-4 and TOP-001-3, which are assigned a High VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a High VRF. Failure to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the primary Control Center, for performing Real-time monitoring and analysis could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements are not directly connected to an area identified in the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	These are new requirements. Approved COM-001-2.1 Requirement R9 requires periodic testing of Alternate Interpersonal Communications capability and is assigned a Medium VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5, proposed TOP-001-4, and approved COM-001-2.1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for Medium VRF. Failure to periodically test primary Control Center data exchange capabilities for redundant functionality could, under anticipated data exchange infrastructure failure, affect the ability to monitor and control the BES. However, failure to test primary Control Center data exchange capabilities for redundant functionality is not likely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VSL Justification

VSLs for TOP-001-4 Requirement R10			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

VSL Justifications for TOP-001-4 Requirement R10	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved TOP-001-3 Requirement R10.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for TOP-001-4 Requirement R10	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22			
Lower	**Moderate**	**High**	**Severe**
The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with one identified entity, or 5% or less of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with two identified entities, or more than 5% or less than or equal to 10% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with three identified entities, or more than 10% or less than or equal to 15% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with four or more identified entities or greater than 15% of the identified entities, whichever is greater.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved IRO-002-4 Requirement R1 and approved TOP-001-3 Requirements R19 and R20.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The applicable entity had data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), but did not have redundant and diversely routed data exchange infrastructure	The applicable entity did not have data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), as specified in the Requirement.

		within its primary Control Center, as specified in the Requirement.	

VSL Justifications for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24			
Lower	**Moderate**	**High**	**Severe**
The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 180 calendar days since the previous test; OR The applicable entity did not test its primary Control Center data exchange capabilities for redundant functionality; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-01 - Modifications to TOP and IRO Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Reliability Standard requirements developed in Project 2016-01. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. 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.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

Project 2016-01 Reliability Standards Requirements

The SDT developed new or revised requirements in IRO-002-5 and TOP-001-4 to address reliability objectives outlined in the project Standard Authorization Request (SAR). The VRF and VSL justification for these new and revised requirements is described below. VRF and VSL justification for requirements that were not modified in Project 2016-01 can be found on the Project 2014-03 Project Page.

VRF Justification

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirement is not directly connected to an area identified in the Blackout Report.

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The proposed VRF is unchanged from approved TOP-001-3 Requirement R10. Additionally, the requirement is similar to approved IRO-002-4 Requirement R3 which applies to Reliability Coordinators and is assigned a High VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement addresses a single reliability objective and has a single VRF.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Operations Planning time horizon, which are not the subject of the Blackout Report recommendations regarding data exchange. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements address data exchange capabilities for the Operations Planning time horizon only, which is a significant change from approved IRO-002-4 Requirement R1 and TOP-001-3 Requirements R19 and R20 which apply to all operations time horizons. As proposed, the VRF will establish consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a Medium VRF. Failure to have data exchange capabilities necessary for performing Operational Planning Analysis or for developing an Operating Plan for next day operations could directly and adversely affect the electrical state or capability of the BES, or the ability to effectively control or restore the BES. However, this failure is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Same-day Operations and Real-time Operations time horizons. A High VSL is assigned to reflect the potential impact on the reliability of the BES consistent with the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements improve upon requirements for data exchange capabilities in approved IRO-002-4 and TOP-001-3, which are assigned a High VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a High VRF. Failure to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the primary Control Center, for performing Real-time monitoring and analysis could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements are not directly connected to an area identified in the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	These are new requirements. Approved COM-001-2.1 Requirement R9 requires periodic testing of Alternate Interpersonal Communications capability and is assigned a Medium VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5, proposed TOP-001-4, and approved COM-001-2.1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for Medium VRF. Failure to periodically test primary Control Center data exchange capabilities for redundant functionality could, under anticipated data exchange infrastructure failure, affect the ability to monitor and control the BES. However, failure to test primary Control Center data exchange capabilities for redundant functionality is not likely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VSL Justification

VSLs for TOP-001-4 Requirement R10			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

VSL Justifications for TOP-001-4 Requirement R10	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved TOP-001-3 Requirement R10.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for TOP-001-4 Requirement R10	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22			
Lower	**Moderate**	**High**	**Severe**
The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with one identified entity, or 5% or less of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with two identified entities, or more than 5% or less than or equal to 10% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with three identified entities, or more than 10% or less than or equal to 15% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with four or more identified entities or greater than 15% of the identified entities, whichever is greater.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved IRO-002-4 Requirement R1 and approved TOP-001-3 Requirements R19 and R20.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The applicable entity had data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), but did not have redundant and diversely routed data exchange infrastructure	The applicable entity did not have data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), as specified in the Requirement.

		within its primary Control Center, as specified in the Requirement.	

VSL Justifications for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24			
Lower	**Moderate**	**High**	**Severe**
The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 180 calendar days since the previous test; OR The applicable entity did not test its primary Control Center data exchange capabilities for redundant functionality; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate~~d~~ action within 8 hours to restore the redundant functionality ~~in more than 8 hours~~.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

Standards Announcement

Project 2016-01 Modifications to TOP and IRO Standards
IRO-002-5 and TOP-001-4

Final Ballots Open through December 12, 2016

Now Available

Final ballots for **IRO-002-5 – Reliability Coordination - Monitoring and Analysis** and **TOP-001-4 – Transmission Operations** are open through **8 p.m. Eastern, Monday, December 12, 2016**.

Balloting

In the final ballot, votes are counted by exception. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballots. Ballot pool members who failed to vote during the previous ballots can vote in the final ballots. Votes from the previous ballots are automatically carried over for ballot pool members who do not participate in the final ballots.

Members of the ballot pools associated with this project can log in and submit their vote for the standards here. If you experience any difficulties using the Standards Balloting & Commenting System (SBS), contact Wendy Muller.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

The voting results for the standards will be posted and announced after the ballots close. If approved, the standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Ballot Name: 2016-01 Modifications to TOP and IRO Standards IRO-002-5 FN 3 ST
Voting Start Date: 12/2/2016 4:37:17 PM
Voting End Date: 12/12/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 245
Total Ballot Pool: 269
Quorum: 91.08
Weighted Segment Value: 74.3

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	65	1	33	0.717	13	0.283	0	16	3
Segment: 2	8	0.7	5	0.5	2	0.2	0	1	0
Segment: 3	60	1	31	0.66	16	0.34	0	7	6
Segment: 4	17	1	9	0.692	4	0.308	0	2	2
Segment: 5	61	1	28	0.7	12	0.3	0	12	9
Segment: 6	45	1	23	0.657	12	0.343	0	7	3
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.9	9	0.9	0	0	0	0	0
Totals:	269	6.9	141	5.126	59	1.774	0	45	24

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Abstain	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Negative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lakeland Electric	Larry Watt		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Westar Energy	Kevin Giles		Negative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Abstain	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	N/A
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Negative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Sing Tay	Negative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Abstain	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Negative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	James Frauen		None	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Negative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Abstain	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Georgia System Operations Corporation	Guy Andrews		Negative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	City of Independence, Power and Light Department	Jim Nail		Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine	Colby Bellville	Negative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Abstain	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Kevin Nielsen		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Abstain	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Negative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	N/A
6	Colorado Springs Utilities	Shannon Fair		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Negative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Showing 1 to 269 of 269 entries

BALLOT RESULTS

Ballot Name: 2016-01 Modifications to TOP and IRO Standards TOP-001-4 FN 3 ST
Voting Start Date: 12/2/2016 4:35:08 PM
Voting End Date: 12/12/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 273
Total Ballot Pool: 301
Quorum: 90.7
Weighted Segment Value: 72.52

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	41	0.651	22	0.349	0	7	5
Segment: 2	8	0.7	5	0.5	2	0.2	0	1	0
Segment: 3	67	1	37	0.638	21	0.362	0	3	6
Segment: 4	19	1	12	0.706	5	0.294	0	0	2
Segment: 5	70	1	37	0.673	18	0.327	0	4	11
Segment: 6	49	1	28	0.636	16	0.364	0	2	3
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	9	0.9	9	0.9	0	0	0	0	0
Totals:	301	6.9	172	5.004	84	1.896	0	17	28

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Negative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Negative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Chris Gowder	Negative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Negative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Jason Snodgrass	Stanley Beasley	None	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Mike Beuthling	Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Negative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
1	Oncor Electric Delivery	Lee Maurer	Joshua Smith	Negative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Negative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	N/A
1	Western Area Power Administration	sean erickson		Negative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Negative	N/A
3	City of Vero Beach	Ginny Beigel	Chris Gowder	Negative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Negative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Chris Gowder	Negative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Mike Beuthling	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Kissimmee Utility Authority	Anthony Darnell		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Sing Tay	Negative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Negative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Negative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Negative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Negative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Negative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Negative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	Acciona Energy North America	George Brown		None	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Negative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine	Colby Bellville	Negative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Jaclyn Massey		Affirmative	N/A
5	Eversource Energy	Timothy Reyher		Affirmative	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann	Chris Gowder	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	N/A
5	Great River Energy	Preston Walsh		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Negative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Abstain	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	N/A
5	SunPower	Bradley Collard		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Negative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	N/A
6	Colorado Springs Utilities	Shannon Fair		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Agency	Richard Montgomery	Chris Gowder	Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Salt River Project	Bobby Olsen		Negative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Exhibit G

Standards Drafting Team Roster

Standard Drafting Team Roster

Project 2016-01 Modifications to TOP and IRO Standards

	Name	Entity
Chair	Jason Smith	Southwest Power Pool, Inc.
Vice Chair	David Bueche	CenterPoint Energy Houston Electric, LLC.
Members	Daniel Hawk	Louisville Gas and Electric Co.
	Saad Malik	Peak Reliability
	Mark Riley	Associated Electric Cooperative, Inc.
	Linwood Ross	Duke Energy Carolinas
	Josh Shultz	Tennessee Valley Authority
PMOS Liaison	Rod Kinard	Oncor Electric Delivery Company
NERC Staff	Mark Olson, Senior Standards Developer	North American Electric Reliability Corporation
	Lauren Perotti, Counsel	North American Electric Reliability Corporation